DESIGN CONCEPTS AND PRELIMINARY ECONOMICS FOR COAL/OIL SHALE COMBUSTION RETORT SYSTEMS

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Mineral Resources Division
Department of Natural Resources
New Brunswick

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Copies available by contacting:

Mineral Resources Division
Department of Natural Resources
P. O. Box 6000, Fredericton, N.B.
E3B 5H1

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Author: Research and Productivity Council, Mineral Development and Processing

Cover: Tim Fevens

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Research and
Productivity Council
Mineral Development
and Processing

SUMMARY

New Brunswick has appreciable fossil-fuel reserve potential, particularily in oil shales and to a lesser extent in coal. Each of these resources on their own, however, have problems which could restrict their development. In the case of coal, increasing concern related to SO_2 emissions undoubtably will result in additional " clean-up" costs for utilities and/or the coal mining operation. These additional costs could result in New Brunswick coal being uncompetitive with relatively low-sulphur imported coal. As the Power Commission is the only real market for New Brunswick coal, there need be concern for the existence, let alone expansion of coal mining in New Brunswick. Similarily New Brunswick oil shales, which as yet are not mined, must attract investment in competition with alternate new Canadian fossil fuel developments, off shore oil, tar sands, etc. To offset these problems it is proposed that both coal and oil shale resources can be used together, in a complimentary way, to overcome these difficulties and effect an attractive, economically viable, energy recovery system.

The Research and Productivity Council (RPC) has successfully demonstrated that Albert Mines Oil Shale can be used as a fluid bed scrubber medium to effectively fix SO_2 from sulphur rich (> 6.8% S) coal. (Reports MDP/81/20, MDP/82/25).

Demonstration trials with SO_2 charged gas to a fluid-bed combustor containing only oil shale or combustion of blends of oil shale and coal have shown that at shale feed size (-¼" inch) and spacial gas velocities (> 160 cm/sec.) comparable to that required for commercial combustors; SO_2 reductions of 93, 87 and 48% respectively can be achieved for oil shale/coal ratios of 3.11:1, 2.43:1 and 1.83:1 respectively. The implications of this work are that oil shale can be a favourable, more economically viable, alternative to limestone as a medium for control of sulphur emissions from fossil fuel-fired electric generating facilities.

Continued use of New Brunswick sulphur rich (> 7% S) coals, will eventually necessitate control of SO_2 emissions and coal/oil shale blends, rather than the more conventual coal/limestone mixtures, as feed to fluid-bed combustors for steam generation would appear to be a solution. The sulphur from the coal is fixed on the spent shale, with the shale combustibles contributing to thermal output. Similarily oil shale can be used in place of limestone as a combustion scrubber medium to clean SO_2 emissions from existing conventional coal-fired plants.

Several scenarios for the co-use of high sulphur coal and oil shale are proposed in this report. All involve recovery of energy from oil shale as steam or a combination of steam recovery plus liquid refineable fuels. Steam recovery can be used to increase MWe capacity at existing power stations, or for direct sale to users of process steam. An example of the latter would be sale from a Dalhousie based plant to the International Paper mill which presently imports up to 700,000 bbl oil/yr for steam generation. Retorted oil from shale can be beneficial either as an energy storage feature for power generation or as crude for refineable higher valued fuels.

Table 1 shows the possible costs for several oil shale/coal scenarios. These costs are estimates, for illustrative purposes only, and hence should not be construed to have a high degree of accuracy. The Base Case represents Dalhousie No.2 with no gas scrubbing, but with costs included for coal washing. This cost, for the Base Case, of 44 mills/kwh will raise to approximately 57 mills/kwh if conventional limestone scrubbers are included. As an alternative to limestone as a scrubber medium, we propose the use of oil shale to be used in a fluid-bed combustion scrubber (FBCS). This would reduce overall annual costs for "clean" coal burning to 52 mills/kwh. These costs could be reduced still furthur through the use of an oil shale "Retort Interlock" with the combustion scrubber which would use spent shale rather than raw shale. The possible decrease in overall costs would accure from the sale of a liquid fuel mix which would return higher value than would simple combustion of oil shale for steam generation.

The retort interlock system has not as yet been demonstrated and hence costs can not be estimated.

The high cost of transportation for large tonnages of coal and oil shale, which would be required for the Combustion Scrubber Option, result in overall costs for this retrofit of Dalhousie NO.2 being higher than would be the case for "new" conventional coal-fired plants with oil shale combustion scrubbers located at either Grand Lake or in Albert County. The higher costs for the Albert County facility, 48 mills/kwh versus 45 mills/kwh, reflect the additional turbine generator capital costs for 90 MWe from the combustion scrubber steam. It is proposed that these costs would not be incurred at Grand Lake where 100 MWe turbine capacity exists if existing oid burners are decommissioned.

The Grand Lake site has many advantages in that existing infrastructure can be used, not only for a commercial plant, but also as a possible alternative to the Chatham Station for pilot plant work which will be required to demonstrate the process. For example the existing 17.5 MWe coal-fired unit would be an ideal source of flue gas for testing the FBCS technology. Rail facilities for transport of oil shale from Albert County to Grand Lake are good and transportation costs would be reduced relative to shipments to Dalhousie. The spent shale also provides excellent land reclamation material for the Grand Lake area. The "basic" nature of the material would provide an excellent buffer for acid drainage problems associated with high sulphur coal mining. Apart from the buffer ability of the spent shale additional work is required to establish possible nutrient content to sustain revegetation.

Co-combustion of coal and oil shale in a fluid-bed combustor (Options I and II; Table 1), located either in Albert County or at Grand Lake, also looks attractive, however units have not as yet been commercialized on large scale and hence more information both on performance, such as will be provided from the test work now being undertaken by Nova Scotia Power and EMR, and on costing is required so that more accurate comparisons can be drawn with conventional coal-fired units equipped with oil shale combustion scrubbers. What is clear however, is that fluid-bed combustors

fueled with coal/oil shale appear to be a better alternative, for New Brunswick, than the coal/limestone mixtures proposed for Nova Scotia.

The Retort Interlock Options, which require laboratory testing, offer energy recovery possibilities which are otherwise lost in conventional retort systems. In the Colorado oil shale retorts, for example, losses are incurred in the shale fines which are rejected, or must be processed at extra cost, and in "char" residues in spent shale. Both the fines and char in our proposed flow sheets (Figures 1, 2 and 3) are used as combustion fuel. The end result being that the profitabity of the retort operation should be increased substantially without undue extra cost in the steam generating component of the plant (Option II; Table 1).

The integration of an electric power facility and retorting is totally complimentary. Estimates for the Colorado oil shales are that 100 MWe of electricity will be required for mining and processing for every 45,000 bbls/day of shale oil. The initial retort operation in New Brunswick, based on a 5,000 ton/day mining rate would produce less than 3,500 bbls/day of shale oil, assuming 20% loss of kerogen to be recovered in the combustor. Although this would require less than 8MWe captive electric generating capacity, expansion of oil shale mining to world scale levels of 50,000 bbls/day of recoverable oil would begin to require more than 50% of the proposed 200 MWe generating station.

The design concepts and cost information outlined in this report will serve to formulate future direction in the Research and Development program leading to large scale demonstration trials.

TABLE 1
SUMMARY OF COSTS
(1982 CAN. DOLLARS)

Option	Location	MWe	Technology	Capital Cost	Annual Cost Capital and Operating
Base Case	Dalhousie	200	Dalhousie No.2	$883/kw	44 mills/kwh
—	Dalhousie	200	Dalhousie No.2 with Ls. Scrubber	$1150/kw	57 mills/kwh
III	Dalhousie	200 90	Dalhousie No. 2 with Oil Shale Combustion Scrubber	$968/kw	52 mills/kwh
IV	Dalhousie	290	Dalhousie No.2 with Spent Oil Shale Combustion Scrubber and Retort Interlock	Insufficient Data	Insufficient Data
I	Albert Co.	290	Coal/Oil Shale Fluid-Bed Combustor	$755/kw	41 mills/kwh
II	Albert Co.	290	Coal/Spent Oil Shale Fluid-Bed Combustor with Retort Interlock	$831/kw*	43 mills/kwh*
—	Grand Lake	290	Coal/Limestone Fluid-Bed Combustor	$755/kw	51 mills/kwh
V	Grand Lake	290	"New" Conventional Coal Burner with Oil Shale Combustion Scrubber	$968/kw	45 mills/kwh
VI	Albert Co.	290	As Above	$1096/kw	48 mills/kwh

* Does Not Include Costs For Retorting.

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1.0 INTRODUCTION

This report utilizes the experimental work completed to date to generate a number of possible scenarios for joint development and utilization of New Brunswick coal and oil shale resources, the general concept being that energy associated with the oil shale is recovered either as steam for direct use for electric power generation, or as liquid refinable oil products. The sulphur from the coal is captured on the spent shale. The options for co-use of oil shale and coal are numerous and hence this report can deal with but a few for which relevant balances are provided as are considerations for plant design.

Estimated capital and operating cost are provided for three coal/oil shale options, namely:

1. New Plant - Coal/Oil Shale Fluid-bed Combustion
2. New Plant - Coal/Spent Oil Shale Fluid-bed Combustion with Oil Shale Retorting.
3. Retrofit - Dalhousie No. 2 with Oil Shale Combustion Scrubber.

The costs for these plants are contrasted with costs for conventional limestone scrubbers and coal/limestone fluid-bed combustion.

2.0 ALTERNATIVE SCENARIOS FOR OIL SHALE UTILIZATION

The conventional approach to oil recovery from oil shale is via retorting. This technology is presently being commercialized in Colorado where reserves of 104 L/T oil (23 I.G./T) exceed 480 billion barrels. New Brunswick reserves of comparable grade will be considerably less than this and hence may not offer the same opportunities for the several large mining operatings planned for Colorado. For this reason smaller scaled operations supplying sufficient shale to balance sulphur emissions from coal-fired electrical generating stations could be a preferred route in New Brunswick. Alternatively New Brunswick coal could be used to supply the thermal requirements for an oil shale retort operation. To this end five coal/oil shale utilization scenarios are proposed:

I Coal/Oil Shale Co-Combustion.

II Coal/Spent Oil Shale Combustion with Retort Interlock

1. Direct Retort Fueling using Heat From Combustor.
2. Indirect Retort Fueling using Heat From Combustor.

III Oil Shale Combustion Scrubber.

IV Oil Shale Combustion Scrubber with Retort Interlock.

The first two options are for new fluid-bed combustors presumably located at the shale site, while the latter two options are retrofits to existing conventional coal burning units such as that of Dalhousie No.2. The overall costs in mills/kwh for all four options are shown in Table 1. These are contrasted with costs for Dalhousie No.2 using washed Minto coal, plus flue gas scrubbing, and with conventional coal/limestone fluid-bed combustion.

All balances in this report are based on 25 IG/T oil shale, the reserves of which are sufficient to sustain a minimum 6000 STPD mining operation for 30 years (pers. comm. D. Gemmell Dept. Natural Resources).

2.1 COAL/OIL SHALE CO-COMBUSTION

As the required oil shale/coal ratio for 90% sulphur fixation is 2.5:1 in fluid-bed combustors or combustion scrubbers, considerable cost advantage can be realized if transportation distance for the shale is minimized. The preferred location for a power station which would utilize oil shale would be in Albert County at the oil shale site. Although additional study would be required to properly assess the relative technological advantages, we have selected fluid-bed co-combustion of oil shale and coal rather than conventional coal burning of coal and fluidized combustion of shale for a new plant because of apparent economic advantages. Although fluid-bed coal combustion has yet to be commercialized the inherent advantages that the system holds for combustion of sulphur rich, high ash, coals is the motivation for federal government support for the system in Western Canada and in Nova Scotia. In the latter case, a 150 MWe coal/limestone fluidized-bed combustor is planned for the mid 1980's.

For New Brunswick high sulphur coal (> 7% S) a 90% reduction in sulphur emission can be achieved by the addition of 1.2-1.5 tons of limestone per ton of Minto coal. However, the use of oil shale as a replacement for limestone would appear to be the more economic alternative; ie. overall costs of 41 mills/kwh compared with 51.0 mills/kwh. The economic advantage in favour of shale is due, in the main, to the energy available in the shale. Details on Capital and Operating Costs for fluid-bed coal/oil shale combustion are given in Appendix C (Table C2, C3 and C4).

2.2 COAL/SPENT OIL SHALE COMBUSTION WITH RETORT INTERLOCK

In this option spent rather than raw oil shale is used as the desulphurizing medium in the fluidized-bed coal combustor. The spent shale is derived from a separate retorting operation.

2.2.1 DIRECT RETORT FUELING

The energy for the retort is derived, indirectly from a "nitrogen loop" within the coal combustor (Figure 1). As an alternative to the nitrogen loop, a bleed of hot flue gases from the combustor can be fed directly into the retort. The dilute product gases from the retort can then be recycled back into the freeboard of the combustor. This system has the distinct advantage of more complete utilization of carbon than would otherwise be the case in a conventional retort. Losses in conventional retorting occur as a result of discard of fines ahead of the retort and char formation in the retort. In the system proposed in Figure 1 fines from the grinding mill are feed to the fluidized bed combustor, this plus the char in the retort discharge (spent shale) are available as fuel within the coal combustor.

The capital costs for the fluid-bed coal/spent oil shale combustor ($831/kw) is slightly higher than that for the coal/raw shale combustor ($755/kw). This is because of the larger tonnage of oil shale and coal required for this option. As a direct result, overall costs are also higher 42.8 mills/kwh versus 40.5 mills/kwh. However, this model will ensure even higher return on investment for the retort operation than the 18.0% projected in a study carried out by the New Brunswick Department of Natural Resources (pers. comm. G. Greer). The increased profitability should accue through decreased energy costs to fuel the retort and elimination of the spent shale disposal cost. This latter cost has been incorporated in the coal combustor operating costs. Capital and Operating Costs for this option are given in Appendix C (Tables C5 and C6).

2.2.2 INDIRECT RETORT FUELING

The flowsheet shown in Figure 2 is based on the Tosco Process, the difference is in the method by which the heat requirements for the retort is generated. In the standard Tosco Process heat is generated from a gas-fired burner, while in the RPC proposed flow-

FIG. 1: Conceptual design for an integrated fluidized-bed combustor and direct shale retorting.

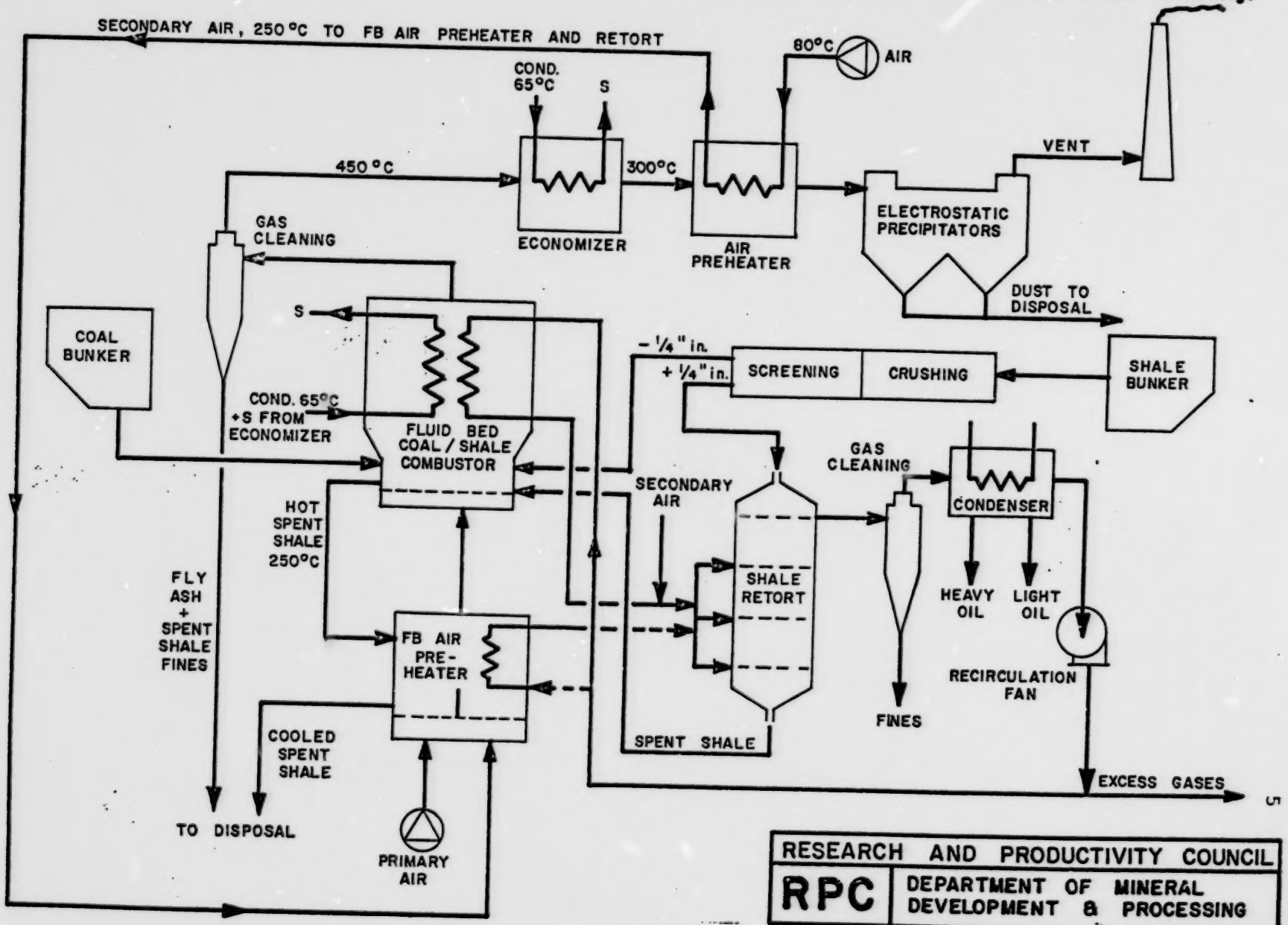

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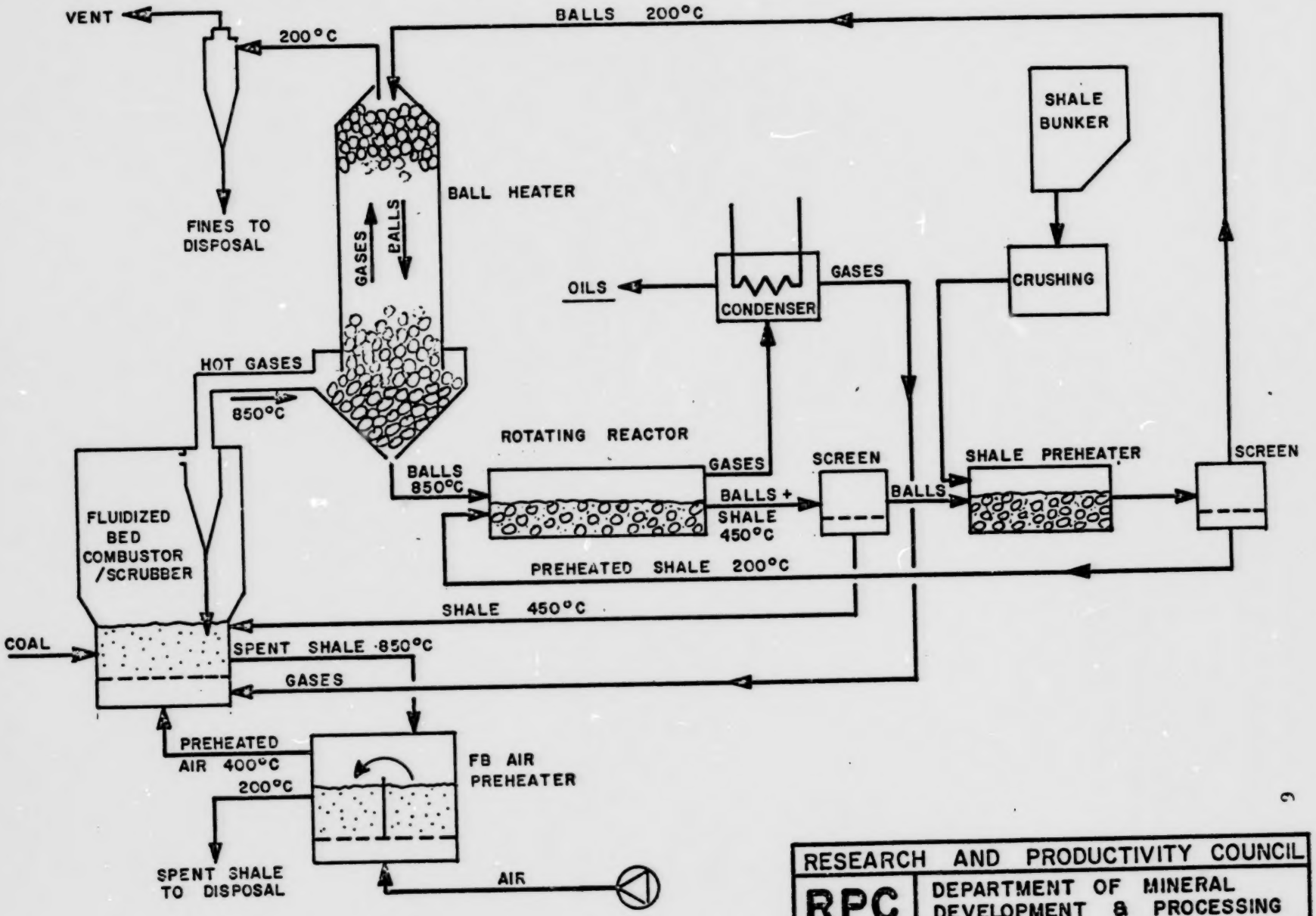
FIG. 2: Conceptual design for an integrated fluidized-bed combustor and indirect shale retorting.



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sheet a coal fired fluidized bed combustor is utilized.

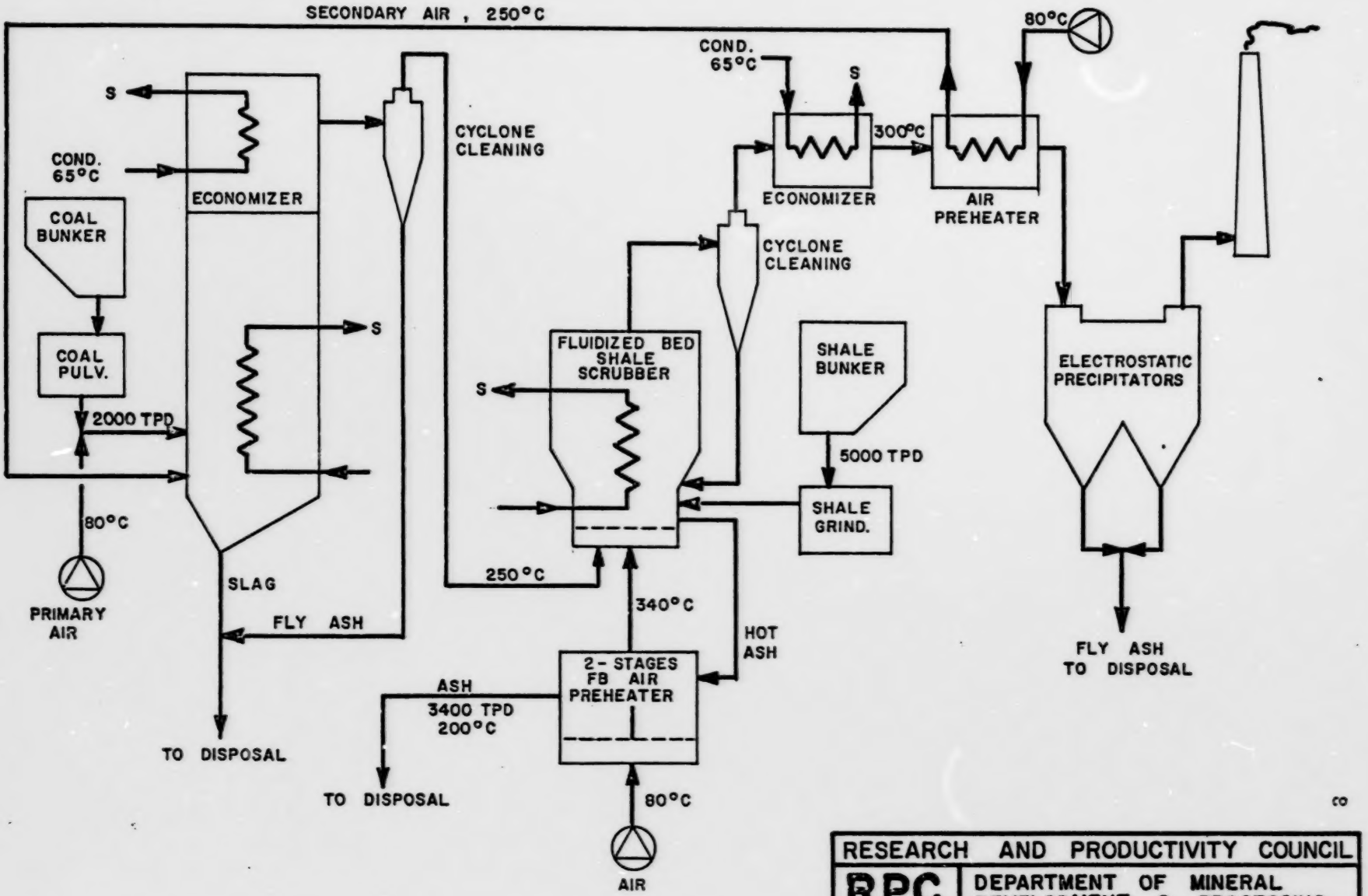
As shown in Figure 2, shale pyrolysis is carried out in a rotating drum. The indirect hear source is hot ceramic balls which enter the drum at ≃ 850°C. As the drum rotates, the hot ceramic balls contact and heat up the oil shale, and kerogen is pyrolyized. Oil is condensed from the product vapours leaving the drum. The gas (not dilutes) can be used as a chemical feed stock or as fuel for on-site use. The solids are continuousely screened to separate the ceramic balls from the spent shale. The residual heat in the ceramic balls is then recovered in a second rotating drum in which the raw shale is preheated to ≃ 200°C before its fed into the pyrolysis drum. The ceramic balls are then lifted by means of a bucketelevator to be fed into the top of the ball heater. The heat requirement for the latter is generated in a fluidized-bed combustor operating on high sulphur product gases (if required), and spent shale as the desulphurizating medium. The residual carbon on the spent shale, which in the standard Tosco Process is not recoverable, will also contribute to the fuel value in the combustor. To increase the efficiency of the process, the available heat in the spent shale is recovered in a fluidized bed heat exchanger to preheat the combustion air.

An important feature of this process is that the fluidized-bed combustor does not have a boiler or cooling coils, hence the problems of errosion/corrosion and control associated with fluid-bed reactors preposed for electrical generation purposes are not present. Other advantages are a) complete utilization of combustible materials, b) higher thermal efficiency, c) high oil yield and d) use of low grade energy (high sulphur coal) to produce higher valued products namely oil and its derivatives.

2.3 OIL SHALE COMBUSTION SCRUBBER

The proposed process flowsheet for integrating a fluidized bed combustor scrubber (FBCS) with an existing coal-fired plant is given in Figure 3. The flue gases, which are charged with

FIG. 3: Conceptual design for an integrated fluidized shale scrubber and power generation.



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particulates and SO_2, from the boiler are fed into a high efficiency cyclone before entering the FBCS for desulfurization. The FBCS which operates on shale only is also fed with sufficient air to burn all the available combustibles in the shale. The combustion air to the FBCS is preheated in a fluidized bed heat exchanger which utilizes the available heat in the spent shale. The off gases from the FBCS then follow their original route ie. through the air heater into the electrostatic precipitators then into the stack. The heat generated in the FBCS will be utilized to raise steam for power generation or alternatively for direct sale to the International Paper Company mill which is approximately 1 mile to the North. This company presently uses up to 700,000 bbls oil/yr to generate steam.

Costs in mills/kwh for this option can be compared directly to costs for Dalhousie No.2 with and without conventional limestone scrubbing. In a 1979 report prepared for the Canadian Electrical Association (Research Program 78-98), cost information was presented for flue-gas desulphurization using limestone scrubbers. This information plus input from N.B. Power staff (P. Whalen) allowed us to estimate costs for a scrubber for Dalhousie No.2. It was also established in the CEA Report that primary coal washing would be required to lower sulphur and ash content of Minto coal if scrubbers, with their 85% sulphur removal limitation, were to achieve even the least stringent emission control standards.[1] Capital costs for the scrubber would approximate $53 mm in 1982 dollars with operating costs $11.8 mm. Total Capital Costs for Dalhousie No.2 plus scrubber equates to $1150/kw with overall costs of 56.9 mills/kwh, this compares with costs for the base plant without scrubber, but treating washed coal, of 43.7 mills/kwh. The costs for cosl washing are estimated at $9/Ton(pers. comm. P. Whalen).

In comparison to the limestone scrubber approach the combustion scrubber overall costs of 52.4 mills/kwh are some what

1. Since this report was written; federal guidelines have been changed and coal washing will now not be required (P. Whalen N.B. Power, pers. comm.)

lower. However, this is considerably higher than are costs for the coal/oil shale combustion option. Much of the cost differential is attributable to the increased freight charges for transporting shale from Albert County to Dalhousie. The significantly lower capital cost per kw for the combustion scrubber option relative to the limestone scrubber is due to the increased MWe output derived from the shale. The steam derived from the shale would be used to drive existing generators already in place at Dalhousie No.1.

Mass and heat balances required for the conceptial design shown in Figure 2 are given in Appendix B. Capital and Operating Costs are presented in Appendix C (Tables C1, C7 and C8).

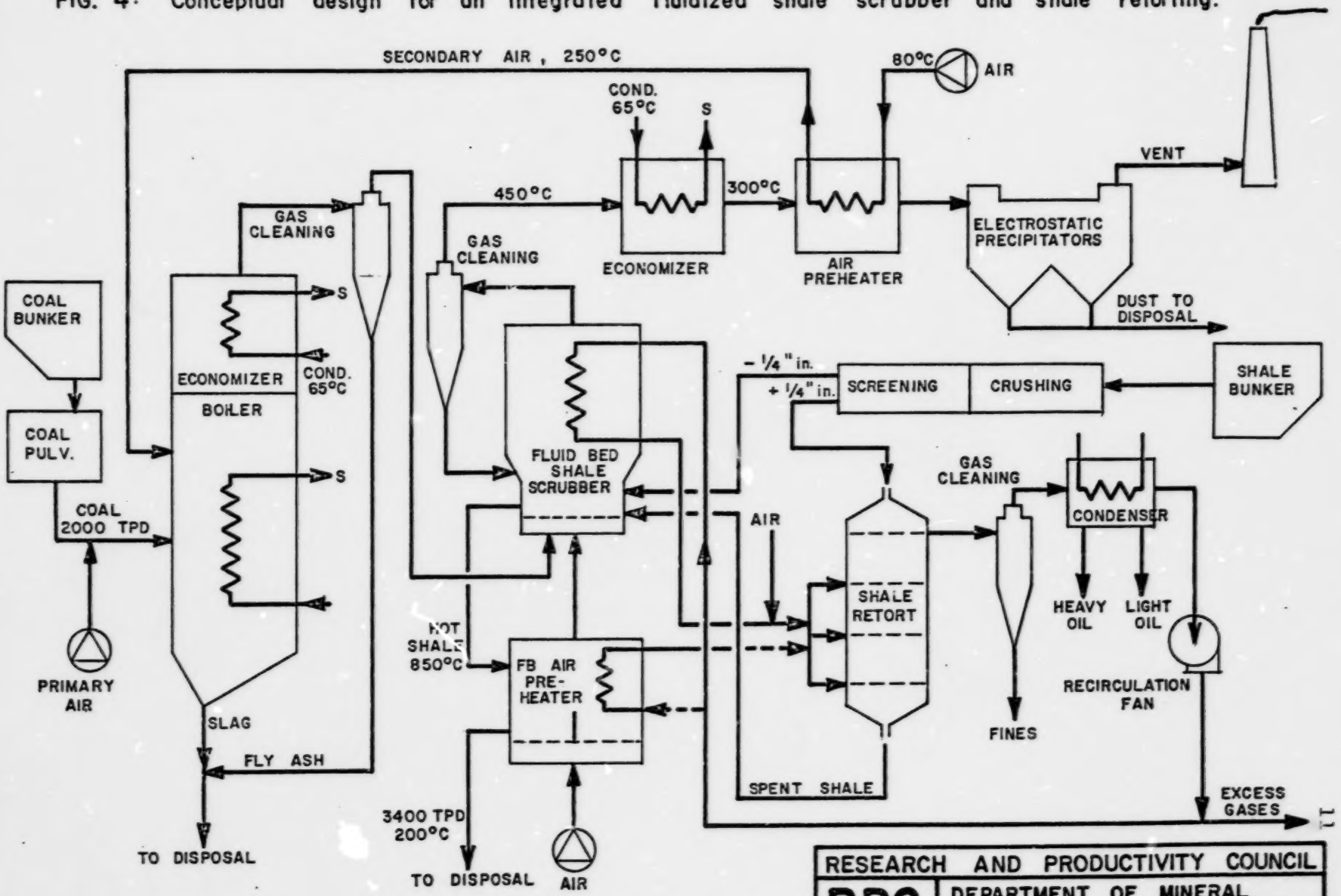
2.4 OIL SHALE COMBUSTION SCRUBBER WITH RETORT INTERLOCK

This approach is similar to the Coal/Spent Oil Shale Combustion with Retort Interlock Option discussed previously, the difference here being that the coal is combusted externally in a conventional coal plant with the flue gas being desulphurized in the combustion scrubber.

The objectives of this option are two fold, a) to utilize the $Ca/MgCO_3$ in the shale to fix SO_2, b) to recover the available oil in the shale. The proposed process flowsheet is given in Figure 4. This process is in some respects similar to the combustion scrubber option, but the emphasis is shifted toward the recovery of the liquid fuel rather than the generation of steam.

The fresh shale after it has been crushed is split into two streams, the coarse fraction +¼ inch to the retort (a modified Paraho Process) and the fine fraction -¼ inch going to the scrubber. The heat generated in the scrubber is then utilized to supply the energy requirements for the retort using nitrogen and other inert gases as the heat transfer media. The spent shale from the retort (almost oil free) is fed into the scrubber to utilize ist Ca and Mg as well as its char content. Before discarding the spent shale from the combustion scrubber it is passed into a fluidized bed heat exchanger in order to prehcat the combustion air for the scrubber.

FIG. 4: Conceptual design for an integrated fluidized shale scrubber and shale retorting.



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As yet this option has not been fully explored, nor costed, due to the lack of data, however the concept seems to have a lot of advantages from the point of view of power generation, the resulting crude oil can be considered as an energy store ie. it can be used as fuel for oil fired peak load power plants.

3.0 PRELIMINARY DESIGN CALCULATIONS

A preliminary design calculation for a FBCS which would be capable of removing > 90% SO_2 from a 200 MWe coal-fired power plant is presented in Appendix B. The calculations and extrapolations were based on mass and energy balance results obtained in test programs MDP/81/20, MDP/82/25 as well as new results given in Appendix A of this report.

In our original concept we envisaged the introduction of the FBCS System to one of the existing 340 MWe oil-fired units at Coleson Cove. With conversion to coal the down-turn ratio would leave excess generating capacity which could be utilized by the steam from the proposed FBCS System. However, following a meeting with N.B. Power Staff it was decided that control associated with two combustion systems to a single turbine could be a major problem. It was suggested by N.B. Power staff that the Dalhousie No.1 generator could be available for FBCS steam, and hence the selection of the Dalhousie site for a preliminary cost study. This system as illustrated in Figure 3 would supply 200 MWe from the conventional coal-fired plant to the No.2 generator and 90 MWe from the FBCS system to the No.1 generator.

Design criteria upon which costing was based for fluid-bed coal/oil shale and coal/limestone combustors was obtained from a publication by D. A. Huber and R. M. Costello titled "Conceptual Design and Cost Estimate 600 MWe Coal Fired Fluidized-Bed Combined Cycle Power Plant" (Combustion V 50 No. 12, 1979).

4.0 ECONOMICS

Capital and Operating cost estimates for the coal/oil shale systems outlined in this report are based on the experimental work to date which defined that 90% sulphur fixation from coal to spent oil shale can be achieved at a ratio of 2.5:1 oil shale to coal.

4.1 INVESTMENT COSTS

4.1.1 CAPITAL COST ESTIMATES

A summary of Capital Cost estimates is given in Table 2. All costs are in constant 1982 Canadian dollars.

The Capital Cost for Dalhousie No.2, ($833/kw) is in 1982 constant dollars and was obtained from a published paper (unknown source) supplied by N.B. Power staff.

Conventional limestone scrubber costs were scaled from data presented in Canadian Electrical Association (C.E.A.) Report 78-98, titled "Air Emission Control Options Canadian Utility Cost Impacts". Mr. P. Whalen (N.B. Power) also provided input. Materials handling and waste management costs were scaled on limestone tonnage while all other scrubber costs were scaled on gas flow. Details on costing are given in Appendix C, Table C9 and also in Notes in Appendix C.

Capital costs for the oil shale combustion scrubber are based on design calculations given in Appendix B. Costs and scale factors are given in Appendix C. Cost estimates are based on a study by Burns and Roe,Industrial Services Corporation, United Technologies Corporation and Babcock % Wilcox company, under contract to the Department of Energy[1]. This study was for a 600 new plant.

(1) Huber D. A., and Costello, R. M., "Conceptual Design and Cost estimate 600 MWe Coal Fired Fluidized Bed Combined Cycle Power Plant" Combustion 50,(12),22 (1979).

The Burns and Roe study included the cost of a carbon burn-up cell, electrostatic precipitators and a number of high temperature high efficiency cyclones, which either would not be required, or already exist at the Dalhousie plant. However, as detailed information was not available at the time this report was written, these items were not excluded from the overall cost given in Table C1. Therefore the estimate given for this option must be considered as upper limit. Costs for the steam turbine generator units and accessory electrical equipment shown in Table C1 are not included in the estimate given in Table C7. These units are available at Dalhousie No.1.

Capital costs for the Coal/Spent Oil Shale Combustion with Retort Interlock, are not detailed as sufficient fundamental data on retorting characteristics and mass and energy balances for the Interlock are not as yet available.

Capital estimates for the Coal/Oil Shale Co-Combustion unit and the Coal/Limestone Fluid-bed Combustor are given in Appendix C. All items are scaled directly from the Burns and Row publication. Capital cost summaries for both units are given in Table C2 and Tables C3 and C9 respectively.

Estimates for the Coal/Spent Oil Shale Combustion component of Option IV shown in Table C5 are scaled from Option III with consideration given for increased costs in materials handling and combustor size.

4.1.2 CAPITAL INVESTMENT CHARGES

A 12% interest rate on debt financing is assumed in all estimates. Interest during construction is added to Total Fixed Investment to determine Total Depreciable Capital Investment.

Capital is carried forward in a sinking fund over 30 years at 12% (Factor 12.41%) to determine an annual cost of capital.

TABLE 2
CAPITAL COSTS
(1982 CAN. DOLLARS)

Option	Location	MWe	Technology	Capital Cost ($,000)	Capital Cost Mills/kwhr*	Comments	Reference
Base Case	Dalhousie	200	Conventional Coal Burner No.2 Unit	$176,000	15.6	-	N.B. Power
———	Dalhousie	200	Dalhousie No.2 Limestone Scrubber	$176,600 $ 53,422 $230,022	15.6 - 20.4	Scrubber Costs Based on Washed Coal (< 6% S)	N.B. Power C.E.A Report 78-98
III	Dalhousie	200 90 290	Dalhousie No.2 Oil Shale Combustion Scrubber	$176,600 $104,110 $280,710	- - 17.1	Steam From Scrubber Supplies No.1 Generator	Huber and Costello
IV	Dalhousie	**	Dalhousie No.2 Oil Shale Combustion Scrubber with Retort Interlock	$176,600 ** **	15.6 **	Steam from Scrubber Fuels Retort	-
I	Albert Co.	290	Coal/Oil Shale Fluid-Bed Combustion	$218,986	13.6	New Plant	Huber and Costello
II	Albert Co.	290	Coal/Spent Oil Shale Fluid Bed Combustion Plus Retort Interlock	$241,129	14.7	New Plant Costs Do Not Include Retort	Huber and Costello
———	Minto	290	Coal/Limestone Fluid-Bed Combustion	$218,986	13.4	New Plant	Huber and Costello

* Annual Cost, Plants Operate @ 80% Capacity.
** Insufficient Available Data

4.2 OPERATING COSTS

4.2.1 COAL

Present Coal costs delivered to Dalhousie are $51/Ton (pers. comm. P. Whalen, N.B. Power). Freight charges are approximately $10/Ton, with handling costs, mine site to rail and rail to Dalhousie No.2, approximately $4/Ton. $51/Ton in used in Options III and IV and $48/Ton in Options I and II. This decreased cost reflects the shorter rail distances from Minto to Albert County.

A surcharge of $9/Ton to clean coal to 6% sulphur and increase BTU content from 23.14 mm BTU/Ton to 26 mm BTU/Ton is assumed for the Dalhousie No.2 base case and Dalhousie No.2 with limestone scrubber. The $9/Ton coal cleaning cost is all inclusive and takes into considertion 15% loss of combustibles (pers. comm. P. Whalen, N.B. Power).

4.2.2 LIMESTONE

Limestone costs, delivered to Dalhousie from the Elmtree Limestone deposit at Petit-Rocher were supplied by G. Doucette of Elmtree Resources Ltd. Costs for ¼ inch stone would approximate $14 to $15 Ton, additional costs for pulverizing would bring the cost to approximately $16/Ton. It is assumed that ¼ inch limestone delivered to Albert County from either Elmtree or from Nova Scotia would be $20/Ton.

4.2.3 OIL SHALE

The mining and crushing costs for oil shale were supplied by G. Greer (Dept. Natural Resources) and rail transportation costs, based on 5000 Tons/Day from Moncton to Dalhousie, were supplied by R. Armitage (Maritime Transportation Commission). Overall costs for oil shale delivered to plant site at Dalhousie would be $15/Ton (Appendix D). Stone costs for a plant in Albert County would be $6/Ton.

4.2.4 OPERATING LABOUR AND SUPERVISION

Estimates for operating labour were based on a number of sources including C.E.A. Report 78-98, Burns and Roe, plus from our own files relating to the RPC Sulphation Roast Process. Average rate in 1982 dollars is $17.79 Man/Hr.

4.2.5 UTILITIES

Cost for utilities, namely steam, process water and electricity are also based on the sources cited above.

4.2.6 MAINTENANCE, LABOUR AND MATERIALS

These charges vary from 2.7 to 9% of Direct Investment the rate being dependant on the complexity of the system, and in particular on the corrosive and errosive nature of the respective system.

4.2.7 ANALYSES

These charges represent laboratory costs for the plant.

4.2.8 DISPOSAL CHARGES

These costs include trucking of material from plant to a land fill disposal site, spreading and maintenace. The disposal site is considered to be less than 10 miles from the plant site. Unit costs decrease with increasing tonnage.

4.2.9 INDIRECT COSTS

Indirect Operating Costs are determined as follows:

Plant Overhead	(50% of Operating Labour, Maintenance, Analyses)
Administration Overhead	(10% of Operating Labour)

Municipal and Provincial Tax	(2.5%(15% Fixed Inv.)
Insurance	(0.15% Depreciable Capital)
Working Capital and Land Costs	(0.3% Direct Inv.)

Operating Costs for each Option are summarized in Table 3 and detailed in Appendix C, Tables C4, C6, C8, C10 and C12.

4.3 PLANT LOCATION

As the oil shale and coal tonnages involved are large; economics dictate that the processing plant be as close to either the shale mine or coal mine sites as possible so as to minimize transportation costs. The favoured situation then would be to locate a new coal-burning power station either in Albert County at the shale mining site or at Grand Lake near the coal mining operations. Fluidized-bed combustion for high sulphur high ash Minto coal, using oil shale as the bed material for sulphur capture, would appear to be more cost effective then would be the construction of a new 200 MWe conventional coal-fired boiler with a 90 MWe shale combustion scrubber.

Although the fluid-bed option appears attractive a full scale commercial plant has yet to be built. For this reason a facility in New Brunswick would probably not be feasible unitl one is first constructed and run-in else where. Nova Scotia and the Federal Government are presently evaluating fluid-bed/limestone combustion in a pilot plant and plans are for a 150 MWe unit to be build in Nova Scotia in the mid 1980's.

The combustion Scrubber alternative to fluid-bed combustion can be implimented either as a "new" plant or as a retrofit to existing coal-burning facilities such as at Dalhousie No.2 or as an add-on to one of the three 340 MWE units at Coleson Cove which are slated for conversion from oil to coal. Our original concept

TABLE 3
OPERATING COSTS
(1982 CAN. DOLLARS)

Option	Location	MWe	Operating Cost ($,000)	Operating Cost Mills/kwh*	Comments
Base Case	Dalhousie	200	$39,276.8	28.0	Washed Minto Coal
Base Case + Ls. Scrubber	Dalhousie	200	$39,276.8 $11,844.3 $51,121.2	28.0 8.5 36.5	Washed Minto Coal
III	Dalhousie	200 90	$37,734.9 $33,970.2 $71,705.1	35.3	Unwashed Minto Coal
IV	Dalhousie	**	**	**	Insufficient Data
I	Albert Co.	290	$55,197.3	27.2	Unwashed Minto Coal
II	Albert Co.	290	$56,950.1	28.0	Unwashed Minto Coal
Coal/Limestone Fluid-Bed	Albert Co.	290	$76,446.8	37.6	Unwashed Minto Coal

* Annual Plants Operate @ 80% Capacity.

** Insufficient data

for the combustion scrubber option was to take advantage of the 35% down-turn MWe capacity in this conversion and to replace this with steam from the combustor scrubber. Power Commission staff have however, pointed out several problems with this approach namely lack of site space and envisaged control problems for the steam interlock. For this reason the Dalhousie No.2 site was selected for cost evaluation. The cost of transportation of both shale and coal would put the overall costs of power generation (52 mills/kwh) at Dalhousie higher than for a new conventional coal-burner with shale combustion scrubber located either in Albert County or at Grand Lake. A new plant in Albert County could produce power for less than 48 mills/kwh, while a plant at Grand Lake would incur costs of approximately 45 mills/kwh. This compares with 41 mills/kwh for a fluid bed boiler. A "new" combustion scrubber plus conventional coal-fired boiler in Albert County must absorb an additional $37 mm in capital over that indicated for the Dalhousie No.2 retrofit. This is for turbine generators etc, for the 90 MWe combustion scrubber. A Grand Lake plant, on the other-hand could use the existing 101 gross MWe turbine capacity. Prior to decommissioning of the existing boilers, these facilities could be used for piloting of the combustion scrubber concept.

4.4 ENVIRONMENT CONSIDERATIONS

The experimental data shows spent oil shale to be an excellent capture medium for SO_2 and in contrast to limestone does not suffer the same efficiency decay, at greater than 90% sulphur fixation. Conventional limestone scrubbers have limitations on SO_2 loading such that their maximum scrubbing efficiency would not be sufficient to clean coal gases from New Brunswick coal to even the least stringent emission standards. As such, coal washing would also be required if emission standards are to be met. These limitations do not exist with the oil shale combustion scrubber option and hence there would be no need for expensive coal washing.

Although the economics presented in this report are based on a 2.5:1 ratio, oil shale to coal, mass and energy balances for 3.0:1 and 5.0:1 are also provided in Appendix B. In the case of fluid-bed co-combustion of oil shale and coal, increased oil shale to coal ratios above 2.5:1 do not appear to adversely effect the overall economics. The increased capital cost is offset by the lower cost per delivered BTU for oil shale versus coal, $1.20/mm BTU versus $2.10/mm BTU, respectively. At a shale/coal ratio of 5:1 the overall cost for power generation decreases from 40.5 mills/kwh to 38.0 mills/kwhr.

Although more detailed study is required to evaluate the economic implications of increased oil shale/coal ratios for all scenarios, the environmental considerations are clear; increased oil shale to coal ratios, above 2.5:1 would further decrease SO_2 emissions.

The spent shale exiting the plant will be environmentally stable as indicated from the leaching data in Appendix A. The sulphite problem associated with limestone scrubbers and hence the requirement for post scrubbing sludge treatment, is not present with the process flow sheets outlined in this report. The use of hot discharge shale as a preheater for combustion air effectively oxidizes sulphite to sulphate.

Although the spent shale can be disposed of safely as land fill, more study is required as to possible by-product recovery or use, as is, for other purposes. As an alternative to land fill this material would provide excellent mine backfill either at Brunswick Mining and Smelting, from a Dalhousie based operation, or possibly as backfill for coal or potash mines from an operation based at Grand Lake or in Albert Country. The particle size of the spent shale would also be ideal for aggregate use.

The location at Grand Lake of a new plant also has the advantage of ideal disposal for spent shale for land reclamation purposes. The "basic" nature of the spent shale would provide an excellent buffer for acid mine drainage problems associated with the high sulphur coal.

5.0 PROPOSED RESEARCH AND DEVELOPMENT PROGRAM

The concept of using Albert County, oil shale to fix sulphur from Minto coal in a fluid bed combustor has been demonstrated successfully in a bench scale set-up. The results are most encouraging and hence an attempt has been made in this report to define possible commercial scenarios which will require further study.

Two broad directions have been established; 1) Co-combustion of oil shale and coal either together or separately to generate steam for electric power generation and 2) Integrated power generation and oil shale retorting to produce electricity and liquid and/or gaseous fuels.

5.1 RETORT SYSTEMS

The work required to evaluate these directions should first be towards obtaining more information on retorting characteristics particularly as they would pertain to interlock systems, either to a fluid-bed coal/spent oil shale combustor or to a fluidized bed combustor addition to conventional coal fired plants. Of particular importance will be the testing of a small vertical retort using a relatively oxygen free gas as a heat exchanger to simulate the "nitrogen-loop" shown in Figures 1 and 3.

The retort unit should be disigned for continuous mode of operation at not less than 5 kg/hr shale feed with facilities for integration with a fluid-bed combustor. Variables to be evaluated would include the following:

- physical and chemical characteristics of oil shale (composition and particle and size)
- gas composition
- gas temperature and temperature profile
- gas and solid flow rates and spacial velocities
- retention time, gas solid
- efficiency of retorting and composition of crude distilate

The spent shale discharge will be analyzed for char content and recycled to the fluid bed combustor for evaluation of burning efficiency of the char and to evaluate if sulphur fixation properties are appreciably different from the raw shale already tested.

5.2 FLUIDIZED BED COMBUSTION SCRUBBER

The fluidized bed scrubber concept requires further evaluation, as we have not as yet attempted sufficient tests with externally introduced SO_2 offgas to a combustion scrubber containing either raw or spent shale, to simulate Options III and IV. Both cases involve a simple combustion scrubber " add-on" to extract SO_2 from external flue-gas. In the case of Option III raw shale is used and the energy generated is as steam, in Option IV spent shale is recycled to the combustion scrubber and the energy mix is steam (electricity) and liquid fuels derived from the interlock retort.

The objectives of the proposed experimental program is to establish the effect of the different operating parameters on the overall performance of the FBCS. The criteria for optimum performance are: a) to achive the desired reduction in SO_2 concentration, b) to maximize the combustion efficiency and c) to fully utilize the equipment ie. to maximize the combustion intensity (capital cost). These objectives are not always compatable, therefore the need to establish the optimium bed temperature, bed depth, shale particle size and gas velocity.

RPC's 6 inch fluidized bed combuster will be utilized (after some modifications) as a FBCS. The flue gases from a coal fired plant will be simulated by injecting SO_2 into the flue gases generated by an oil burner. The composition and temperature of the input and output gas streams will be monitored continuously using on-line gas analyzers and thermocouples respectively. The data will be displayed using a multichannel chart recorder. Several thermocouples will also be immersed in the bed to ensure uniform bed temperature.

Particle size, as well as proximate and ultimate analysis of the raw and spent shale, from the bed and from the cyclones will be carried out. This analysis will be used, to confirm the degree of Ca/Mg CO_3 utilization, and to establish the suitability of the spent shale for waste disposal. An estimate of the degree of freeboard reactions can also be obtained from analysis of the spent shale from the bed and from the cyclones.

Once the relationship among the various operating parameters has been identified, it is proposed that scale up effects should be studied by conducting a limited number of tests using RPC's 14" fluidized bed combustor. Once these have been completed and economics and concepts reevaluated in light of results obtained from the retort work, then excellent opportunities exist for the use of N.B. Power 17.5 MWe coal-fired unit at Grand Lake to carry out large pilot scale trials.

5.3 SPENT SHALE CHEMISTRY

The shale chemistry evaluated to date has been directed solely towards environmental considerations. More work is required to evaluate possible by-product recovery, chemical stability and suitability for cement, aggregate, brick production and any others which may be shown economic upon investigation.

5.4 COSTS

Detailed work proposals will be submitted once the client has had an apportunity to comment on this report and discussions have been held as to direction. In general terms a minimum of $250,000 should be budgeted for work during the fiscal year 1982/83.

6.0 ACKNOWLEDGEMENTS

Assistance and helpful information in preparing this report have been obtained from New Brunswick Natural Resources personnel, in particular Don Gemmell and George Greer. Mr. Ramsey Armitage of the Maritime Transportation Commission supplied information on transportation costs and N.B. Power Commission staff including P. Whalen, C. Flynn, M. Thanisch, D. Rankin, M. Dunphy, J. McGrath and J. Mercer all contributed valued input.

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DEPARTMENT OF MINERAL DEVELOPMENT
AND PROCESSING

Roy S. Boorman Ph.D P.Eng
Head, Mineral Development
and Processing

Study Personnel

R. S. Boorman

P. Salib

I. Wilkomirsky

R. Salter

R. Gilders

APPENDIX A
EXPERIMENTAL PROGRAM
COAL/OIL SHALE
FLUIDIZED BED
CO-COMBUSTION

A - 1.0 INTRODUCTION

A schematic of the 6 inch diameter fluidized bed combustion test rig used in this program is given in Figure A1. Details concerning rig design, operation and flue gas analyses have been given in previous reports (MDP/82/85, Jan. 29, 1982; MDP/81/20, Nov. 16, 1981).

A summary of the test conditions and results of the coal/oil shale fluidized bed co-combustion trials is given in Table A-1. To properly assess this data, it is necessary to know the chemical characteristics of the coal and oil shale feeds and the resulting calcines. All calcines produced in the program were assayed and subjected to water and HCl leaching. Only a few of the results and balances; selected due to their significance for plant design, costing, and scale-up; are given in this report. The complete set of analysis reports and balances will be retained in MDP File: 8900 - Experimental (Nov. 1/81 - April 1/82) at RPC. This file is available for study on request.

A-2.0 FEED ANALYSIS

The ultimate analyses of the samples of Albert County Oil shale and Minto coal used in the test program are given in Table A-2. Chemical assay results on coal ash, fresh oil shale, and the calcines from run# OSC-16c are given in Table A-3. Fischer retort assays on the various oil shale samples tested in the program are given in Table A-4.

A-3.0 COMBUSTION EFFICIENCIES

Calculations of total combustion efficiencies for the combined coal-oil shale feeds, based on carbon balances, are given in Table A-5. The efficiencies were greater than 91% in all test runs. The combustion air was controlled to maintain the O_2 content in the flue gas at 2.8± 0.8 vol. % as measured on the gas chromatograph. Measured fluidizing air flow rates corresponded to oxygen in the air blast rates of 1.1-1.15 times

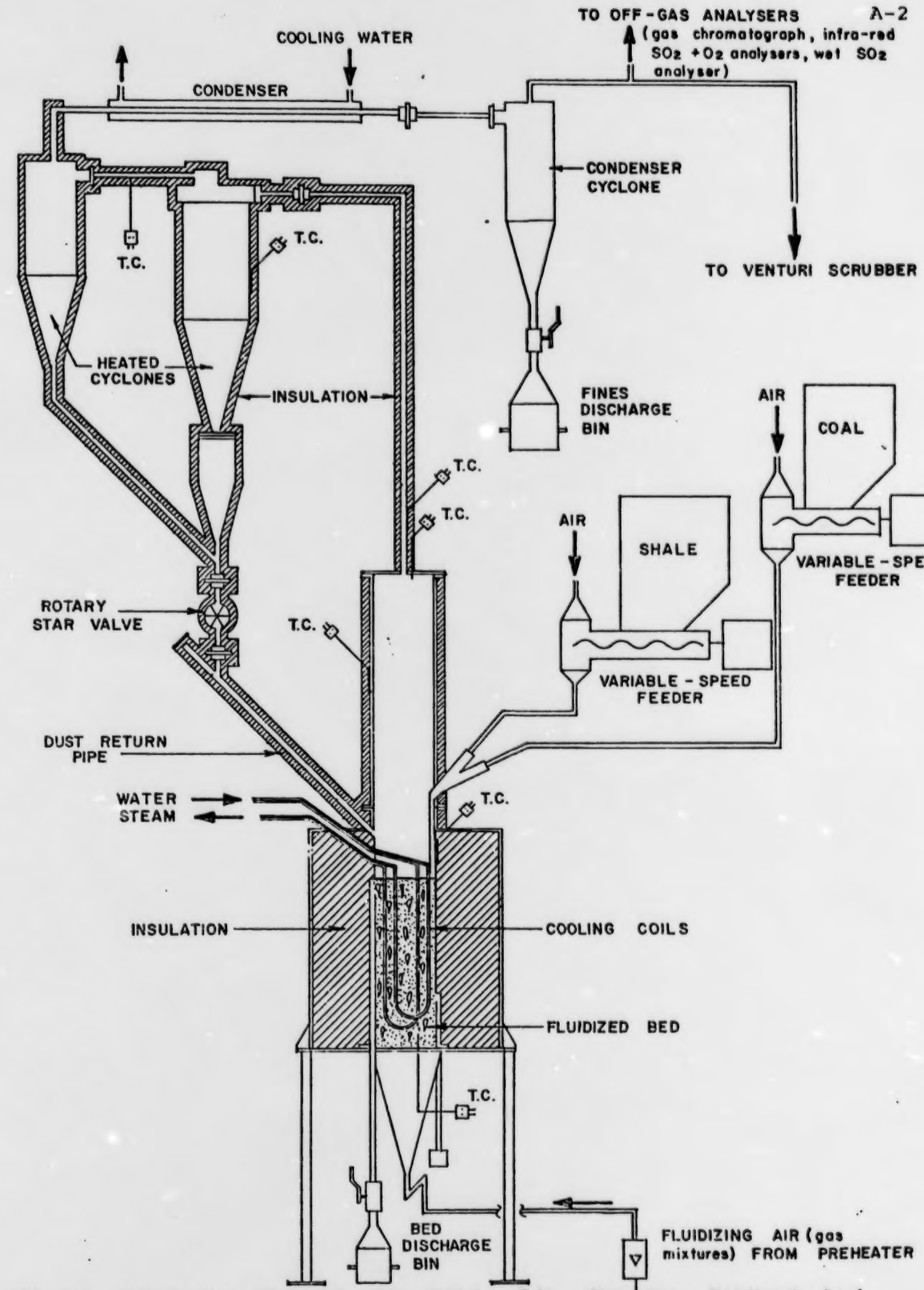

FIG. A1: Schematic view of the R.P.C. 6 in. diameter fluidized bed reactor.

TABLE A-1
COAL/OIL SHALE FLUIDIZED BED COMBUSTION
TEST CONDITIONS AND RESULTS

Run #	Feed Size (mesh)		Feed Rate (kg/hr)		Ratio	Ret. Time	Spacial	Calcine Distribution (%)			Flue Gas SO_2	SO_2 Reduction	Cooling H_2O Rate	Bed T	Free-Board T	Cyclone T
	Oil Shale	Coal	Oil Shale	Coal	Shale/Coal	(hr.)	Velocity (cm/sec)	Bed	Fines	Scrubber	(%)	(%)	(cc/min)	(^oC)	(^oC)	(^oC)
OSC-13	-50 X +200	-8X0	1.88	0.75	2.5:1	2.89	40.5	28.2	30.9	40.9	0.014	95.8	40-50	800-820	750	485
OSC-14	-20 X +100	-8X0	1.40	1.47	0.95:1	3.20	78.5	40.0	59.5	0.5	0.25	53.0	140-160	800-820	730	560
OSC-15a	-20 X +100	-8X0	1.77	1.78	1:1	2.56	79.2	63.8	35.8	0.4	0.20	60.0	130-160	800-820	750	565
OSC-15b	-20 X +100	-8X0	2.19	1.90	1.11:1	2.15	81.0	67.9	31.6	0.5	0.18	63.3	140-170	800-820	750	575
OSC-16a	-20 X +100	-8X0	2.34	1.72	1.36:1	2.09	81.0	72.0	27.9	0.1	0.21	55.0	115-130	800-820	740	570
OSC-16b	-20 X +100	-8X0	2.64	1.50	1.76:1	1.95	81.0	74.3	24.0	1.7	0.045	89.3	115-130	800-820	760	580
OSC-16c	-20 X +100	-8X0	3.64	1.39	2.62:1	1.50	81.0	77.3	21.9	0.8	0.021	95.1	110-130	800-820	750	570
OSC-17a*	- 8 X + 50	-¼X+20	3.69	3.60	1.03:1	1.24	157.0	72.8	26.3	0.9	0.42	29.6	230-350	800-820	785	675
OSC-17b*	- 8 X + 50	-¼X+20	4.25	3.60	1.30:1	1.12	158.4	73.4	25.4	1.2	0.36	37.9	230-350	800-820	820	730
OSC-17c*	- 8 X + 50	-¼X+20	6.60	3.60	1.83:1	0.79	162.7	72.4	24.9	2.7	0.30	41.8	230-350	800-820	820	750
OSC-17d*	- 8 X + 50	-¼X+20	9.60	3.60	2.67:1	0.57	164.5	77.6	20.5	1.9	0.22	51.4	230-350	800-820	830	760
OSC-18a	- 8 X + 50	-¼X+20	8.90	2.86	3.11:1	0.63	173.5	67.1	32.8	0.1	0.03	93.2	155-175	800-830	800	745
OSC-18b	- 8 X + 50	-¼X+20	5.10	2.10	2.43:1	1.06	162.7	83.4	16.5	2.5	0.06	87.1	200-225	800-830	790	635
OSC-18c	- 8 X + 50	-¼X+20	7.70	4.20	1.83:1	0.67	164.7	68.4	29.1	0.1	0.25	47.8	470-600	800-830	800	630

* OSC - 17 were preliminary runs at high spacial velocities.
Some operating problems concening control of coal and oil shale feed rates were encountered, all results given in the table are average valves but the % SO_2 in the Flue Gas and the % SO_2 REDUCTION will be weighed high and low respectively due to these problems.

TABLE A - 2

ULTIMATE ANALYSES OF OILSHALES AND COAL (WT%)

Sample		C	H	N	S	Ash	Moisture	O
1. Coal (-8 mesh)	sample a	56.6	4.11	0.43	7.35	31.22	0.20	0.1
Tests OSC -13 to OSC -16c	sample b	58.9	4.05	0.46	7.25	28.48	0.05	0.86
2. Oil Shale (-50 +200 mesh)	sample a	14.16	1.57	< 0.2	2.35	73.11	0.27	8.54
Test OSC -13	sample b	14.20	1.52	< 0.2	2.25	73.19	0.26	6.58
3. Oil Shale (-20 +100 mesh)	sample a	11.53	1.39	< 0.2	0.90	76.66	0.34	9.18
Tests OSC -16a to OSC -16c	sample b	11.62	1.32	< 0.2	0.78	75.70	0.31	10.27
4. Coal (-½" +20 mesh)	sample a	59.4	4.01	0.45	9.00	28.51	0.36	< 0.1
Tests OSC -17a to OSC -18c	sample b	60.52	4.06	0.45	8.40	29.07	0.44	< 0.1
5. Oil Shale (-8 +50 mesh)	sample a	10.22	1.22	<0.2	1.00	77.87	0.12	9.57
Tests OSC -17a to OSC -18c	sample b	10.35	1.26	<0.2	0.90	77.29	0.12	10.08
6. Oil Shale (-20 + 100 mesh)	sample a	14.21	1.57	<0.02	0.85	73.20	0.18	9.99
Tests OSC-14 to OSC-15b								

TABLE A - 3

ANALYSES OF FRESH OIL SHALE, COAL ASH, AND COMBUSTION CALCINES

Composition	Fresh Oil Shale (-8 to +50 mesh) OSC -17a to OSC -18c	Coal Ash (-¼" to + 20 mesh) OSC -17a to OSC -18c		Calcines from OSC -16c	
		Sample a	Sample b	Bed	Fines
SiO_2	40.78	40.61	38.79	48.20	39.29
Al_2O_3	12.87	19.01	17.12	17.05	14.92
Fe_2O_3	5.20	31.45	34.85	6.43	17.16
MgO	3.58	1.84	0.58	4.76	3.30
CaO	10.75	3.50	3.32	12.60	9.72
Na_2O	1.28	0.87	0.44	1.20	1.50
K_2O	1.61	2.78	2.36	2.02	1.41
P_2O_5	<0.01	<0.01	<0.01	<0.01	<0.01
MnO	0.12	0.16	0.17	0.14	0.12
TiO_2	0.37	0.33	0.40	0.40	<0.2
Ignition Loss	21.62	-	-	5.29	14.54
Total	98.26	100.55	98.03	98.09	101.96

TABLE A - 4
OIL SHALE ANALYSES BY FISCHER ASSAY

	Shale # 1 Size -50 + 200 mesh Test OSC-13		Shale # 2 Size -20 + 100 mesh Test OSC-16a to OSC-16c		Shale #3 Size -8 + 50 mesh Tests OSC-17a to OSC-18c		Shale # 4 Size -20+100 mesh Tests OSC-14 to OSC-15b
	Sample a	Sample b	Sample a	Sample b	Sample a	Sample b	Sample a
Total Loss (g/100 g shale)	10.5	10.5	9.5	18.0	7.5	7.5	11.5
Weight Oil (g)	7.3	7.6	5.9	5.9	6.6	5.9	9.4
Volume Oil (ml)	8.1	8.7	6.8	6.8	7.6	6.7	10.8
% Oil Yield	7.3	7.6	5.9	5.9	6.6	5.9	9.4
% Water Yield	1.2	1.5	1.4	1.5	0.4	1.2	1.2
% Gas Lost	2.0	1.5	2.3	10.6	0.5	0.5	0.9
Yield Oil (Imp. Gal/Ton)	16.0	17.4	13.6	13.7	15.1	13.4	21.6
Density Oil (g/ml) (15.5^{O}C)	0.8930	0.8695	0.8671	0.8655	0.8745	0.8816	0.8708

TABLE A - 5

CALCULATIONS OF COMBUSTION EFFICIENCIES

Test OSC-14

Feed Rate	(Kg/hr.)	%C	C(gm)	Calcine Discharge Rate	(Kg/hr)	%C	C(gm)
Coal	1.47	57.8	849.66	Bed	0.852	7.65	65.18
Shale	1.40	14.2	198.80	Fines	0.831	0.39	3.24
			1,048.86				68.42

Carbon Combustion Efficiency = 93.5%

Test OSC-16c

Coal	1.37	57.8	803.42	Bed	3.011	0.57	17.16
Shale	3.64	11.6	422.24	Fines	0.553	10.30	56.96
			1,225.66				74.12

Carbon Combustion Efficiency = 94.0%

Test OSC-18a

Coal	2.86	60.0	1,716.0	Bed	7.512	0.70	52.58
Shale	8.90	10.3	916.7				180.74
			2,632.7				233.32

Carbon Combustion Efficiency = 91.1%

stoichiometric for carbon and hydrogen in the combined coal-oil shale feed.

Combustion efficiencies of greater than 91% are very high for a small reactor such as the 6" diameter X 28" deep fluidized bed system used in this study, considering the high feed rates to bed volumes employed. The back mixing properties of a fluidized bed reactor result in a portion of the feed remaining in the reactor for retention times much shorter than the mean value. This portion has a correspondingly low combustion efficiency and the portion increases with decreasing reactor size. Accordingly, scale-up of fluidized bed systems usually result in significant improvements in combustion efficiency. Also, the ratio of bed diameter to bed volume has an effect on calcine elutriation rate; the smaller the ratio, the lower the rate and correspondingly longer calcine retention time in the combustion zone. Again, reactor scale-up will result in an increase in combustion efficiency.

A-4.0 SULPHUR FIXATION

Values for the fixation of sulphur liberated as SO_2 during the combustion of coal on carbonate in oil shale are given in Table A-1 (SO_2 Reduction). These values were determined by comparing the SO_2 strength in the flue gas as calculated from the sulphur input from the coal feed only (no allowance for S in oil shale) and the measured flue gas volume, with the actual SO_2 strength in the flue gas as measured by the gas chromatograph. Sulphur in the shale was not included in the SO_2 reduction calculations as the purpose of the program was to determine the reduction in sulphur emissions from coal combusiton units possible by co-combusting oil shale. Accordingly, the total SO_2 Fixation, considering sulphur in coal and oil shale, would be higher than the SO_2 Reducation given Table A-1. The discrepancy increases as the oil shale/coal ratio increases. Both the SO_2 Reduction and the total SO_2 Fixation are very much dependent upon the sulphur content of the coal and oil shale feed and the carbonate

content of the oil shale. The sulphur contents for the feeds tested in this program are given in Table -2.

Sulphur assays of feeds and sulphur and oxide a says of the calcines can be employed to determine the percentage carbonate in the feed which has been converted to sulphate and/or sulphite in the calcine (% carbonate utilization). These results are given in Table A-6.

A-5.0 CALCINE LEACHING BEHAVIOUR

The conditions and results of fresh oil shale and calcine leach tests in water and weak hydrochloric acid are given in Table A-7. These tests were performed to obtain a preliminary assessment of environmental problems associated with calcine disposal. Note that the pH of the water digests are all basic, greatly diminishing the possibility of heavy metal leaching due to run off from disposed calcine. No heavy metals (Zn, Cu, Hg, Pb, Cd, As) were detected in the leach liquors (detection limit -0.0005 milligrams per 10 gram calcine sample).

The results in Table A-7 were used to produce Table A-8. All elements leached are reported as sulphates, except for calcium for which oxide and sulphur association were determined. It should be noted that most of the leached material was sulphite, not sulphate. Sulphite is generally considered to be an environmentally unsuitable material due to its high C.O.D (chemical oxygen demand). It is proposed in the process flowsheets to reclaim the heat in the calcines in a fluidized air preheater. The sulphites will be oxidized to sulphates in the preheater and accordingly will leach as such on disposal. If oxidized calcine has been employed in the leach tests, an increase in calcium sulphate leaching of about 4 fold would have resulted, due to the higher solubility in water of calcium sulphate than calcium sulphite. Comparison of the normalized results (normalized to 1 Ton of shale feed) shows that the leaching characteristics of calcines are very similar to crushed, uncalcined oil shale.

TABLE A - 6
% CONVERSION OF CARBONATE IN OIL SHALE TO SULPHATE IN CALCINE

Test OSC-14

Feed (gm/hr)		Calcine (gm/hr)		
S in Oil Shale	S in Coal	S	Ca as SO_4	Ca as CaO
11.8	107.3	68.8	86	1.31

% Carbonate Conversion (Utilization) = $\frac{86}{86 + 1.31} \times 100 = 98.5\%$

% Mineral Carbon (Carbon as Carbonate) in Oil Shale Feed = 1.87%

Test OSC-16c

Feed (gm/hr)		Calcine (gm/hr)		
S in Oil Shale	S in Coal	S	Ca as SO_4	Ca as CaO
30.6	101.0	126.6	158	9.64

% Carbonate Conversion = 94.2%

% Mineral Carbon in Oil Shale Feed = 1.38%

Test OSC-18a

Feed (gm/hr)		Calcine (gm/hr)		
S in Oil Shale	S in Coal	S	Ca as SO_4	Ca as CaO
84.6	249.0	316.6	396	30.12

% Carbonate Conversion = 92.9%

% Mineral Carbon in Oil Shale Feed = 1.44%

TABLE A - 7

RESULTS OF WATER AND ACID LEACHING TESTS ON FRESH OIL SHALE AND CALCINES

Calcine	Leach	Milligrams of Element Leached from 10 gm sample						pH of leachate
		S	Na	K	Mg	Ca	Al	
fresh oil shale *	H_2O	27.6	2.2	0.9	0.6	53.0	0.2	11.8
fresh oil shale*	HCl	106.3						
OSC-14 bed*	H_2O	33.0	1.1	1.1	1.6	46.0	0.05	8.3
OSC-14 bed*	HCl	98.9						
OSC-14 fines*	H_2O	41.0	1.8	1.6	0.4	58.0	0.01	9.0
OSC-14 fines*	HCl	60.7						
OSC-16c bed*	H_2O	23.4	1.0	1.0	0.1	56.0	0.05	10.9
OSC-16c bed*	HCl	57.5						
OSC-16c fines*	H_2O	31.9	2.8	1.6	0.1	52.0	0.06	10.4
OSC 16c fines*	HCl	64.5						
OSC-18a bed**	H_2O	67.7	1.7	1.5	1.0	114.8	0.2	8.5
OSC-18a bed**	HCl	156.2						
OSC-18a fines*	H_2O	40.0	1.5	1.3	1.7	68.2	0.2	10.9
OSC-18a fines*	HCl	152.8						

* H_2O leach test - 10 gm of sample in 100 ml of water, 1 hour agitation

* HCl leach test - 10 gm of sample in 100 ml of water containing 2.5 gm of HCl, 1 hour agitation

** H_2O leach test - 10 gm of sample in 200 ml of water.

TABLE A - 8

LEACH BALANCES FOR CALCINES AND OIL SHALE FEED FOR FLUIDIZED BED COMBUSTION TESTS

Run #	Shale Feed (Kg)	Coal Feed (Kg)	Total Calcines (Kg)	Water Leachables * (gm) Na as Na_2SO_4		K as K_2SO_4		Mg as $MgSO_4$		Ca as CaO	as $CaSO_4$	Al as $Al_2(SO_4)_3$		Total
OSC-14	1.40			0.31		0.13		0.08		7.42	10.39	0.03		> 10.4
OSC-14		1.47												
OSC-14			1.68	0.25	0.76	0.22	0.50	0.17	0.84	8.71	1.84	25.14	0.006	0.04	29.08
OSC-14**	1000			221		93		57		5300	7421	21		> 7421
OSC-14**		1470												
OSC-14**			1200	179	543	157	357	121	600	6221	1314	17957	4	29	20771
OSC-16c	3.64			0.80		0.33		0.22		19.29	27.01	0.007		> 27.01
OSC-16c		1.39												
OSC-16c			3.56	0.45	1.4	0.39	0.86	0.04	0.18	19.78	13.49	34.50	0.02	0.11	43.01
OSC-16c**	1000			220	91			60		5299	7420	19		> 7420
OSC-16c**		382												
OSC-16c**			978	124	385	107	236	11	49	5434	3706	9478	5	30	11816
OSC-18a	8.90			1.96		0.80		0.53		47.17	66.04	0.18		> 66.04
OSC-18a		2.86												
OSC-18a			9.78	1.53	4.73	1.34	2.99	1.06	5.25	98.16	42.17	231.32	0.19	1.23	287.52
OSC-18a**	1000			220		91		57		5300	7420	21		> 7420
OSC-18a**		321												
OSC-18a**			1043	172	531	151	336	119	590	11029	4738	25991	21	138	32306

* Leachable in agitation leach (10 gm H_2O:1 gm sample), all components taken as sulphates except Ca for which CaO fraction is known.

** Scaled up to 1 Ton oil shale/hour feed rate to normalize values

Comparing the leaching test with 200 gm of water per 10 gm of calcine (OSC-18a) with the others at 100 gm per 10 gm shows that effectively all the Na, Al, K, and Mg have been leached with only 100 gm water per 10 gm shale. Since solubility constraints effect the calcium sulphate (o.2 gm per 100 gm water) and calcium sulphite leaching (0.05 gm per 100 gm water), calcium sulphate leaching will increase with increasing water addition.

A-6.0 SCALE-UP TO COMMERCIAL POWER GENERATION UNITS

The experimental data given in Table A-1 can be normalized by plotting the efficiency of sulphur fixation (SO_2 Reduction) as a function of the shale to coal ratio for the various spacial (gas) velocities employed. These relationships are shown in Figure A2. This data is in a form suitable for extrapolation to different gas velocities and fluidized bed depths (levels).

From this data the mineral carbon assays on the oil shale, and the sulphur assays on the coal and oil shale, it is evident that an oil shale to coal feed ratio of 2.5 is required to safely achieve 90% sulphur fixation if reactor design and operation allows for sufficient flue gas retention time in the bed. From Figure A2, fixing the shale to coal ratio at 2.5, SO_2 fixations of 75% and 96% are obtainable at gas velocities of 160 and 80 cm/sec. respectively. Plotting these values, converted to percent sulphur fixation per 10 cm of bed depth, versus gas velocity results in Figure A3.

Now, since sufficient carbonate is present in the shale to fix all the sulphur dioxide generated during combusiton, given sufficient reaction time; as the gas velocity approaches zero in Figure A3, the fixation efficiency must approach 100% asymptotically. Therefore, it can be assumed with confidence that the reaction is first order and the shape is as shown in Figure A3. This relationship was used in calculating the curves shown in Figures A2 and A4. The experimental results for the

tests at 163 cm/sec. gas velocity are plotted in Figure A4 to show the agreement with the calculated curve. The depth of the fluidized bed in the 6" diameter test rig is 71 cm (28 inches).

Considerations of boiler operation, flue gas handling, reactor size, pressure drop considerations etc. result in an optimum gas velocity for a commercial scale fluidized bed combustor of around 4 m/sec. Figure A4 shows the predicted relationships between % SO_2 fixation and shale to coal ratios for different reactor bed depths at 4 m/sec. gas velocity. Bed depths should be minimized in fluidized bed reactors to decrease capital and operating costs. According to Figure A5, for a reactor operating at 4 m/sec. and a shale to coal ratio of 2.5 , a bed depth of around 2 m will be required to obtain greater than 90% sulphur fixation efficiency. This is a practical operating bed depth considering the low bulk density and specific gravity of the calcine and the high gas velocities to be employed.

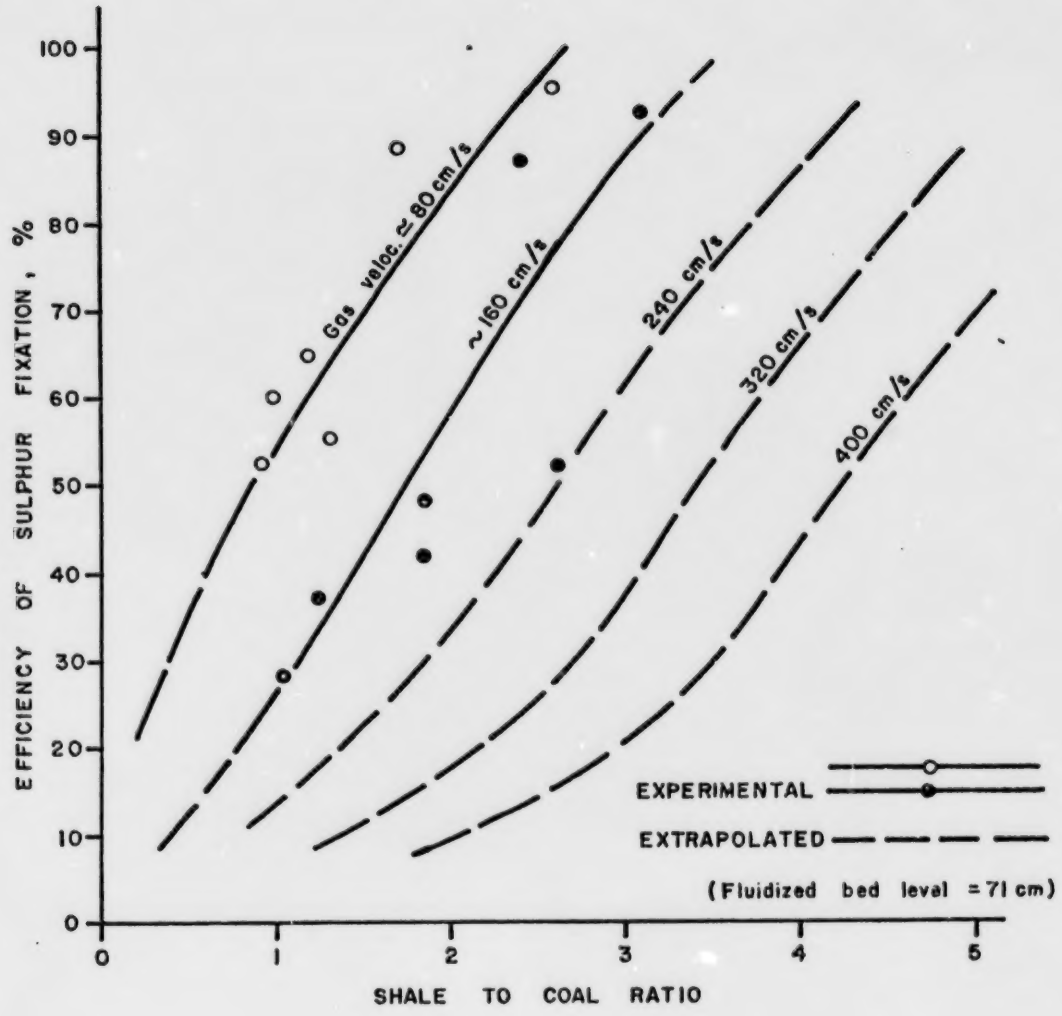

FIG. A2: Influence of the gas velocity on the sulphur fixation for different shale to coal ratios.

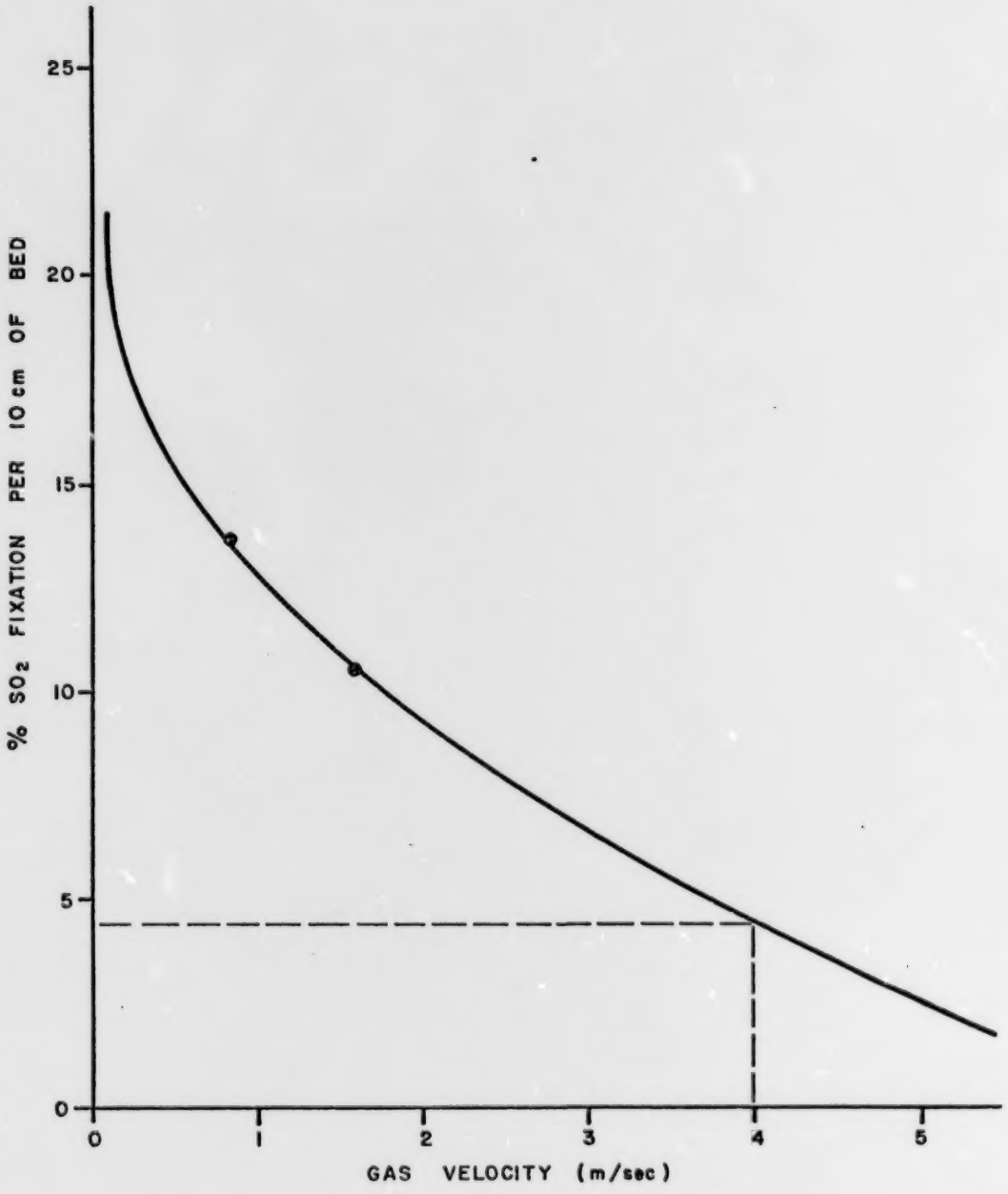

FIG. A3: The effect of velocity on the efficiency of SO_2 fixation.

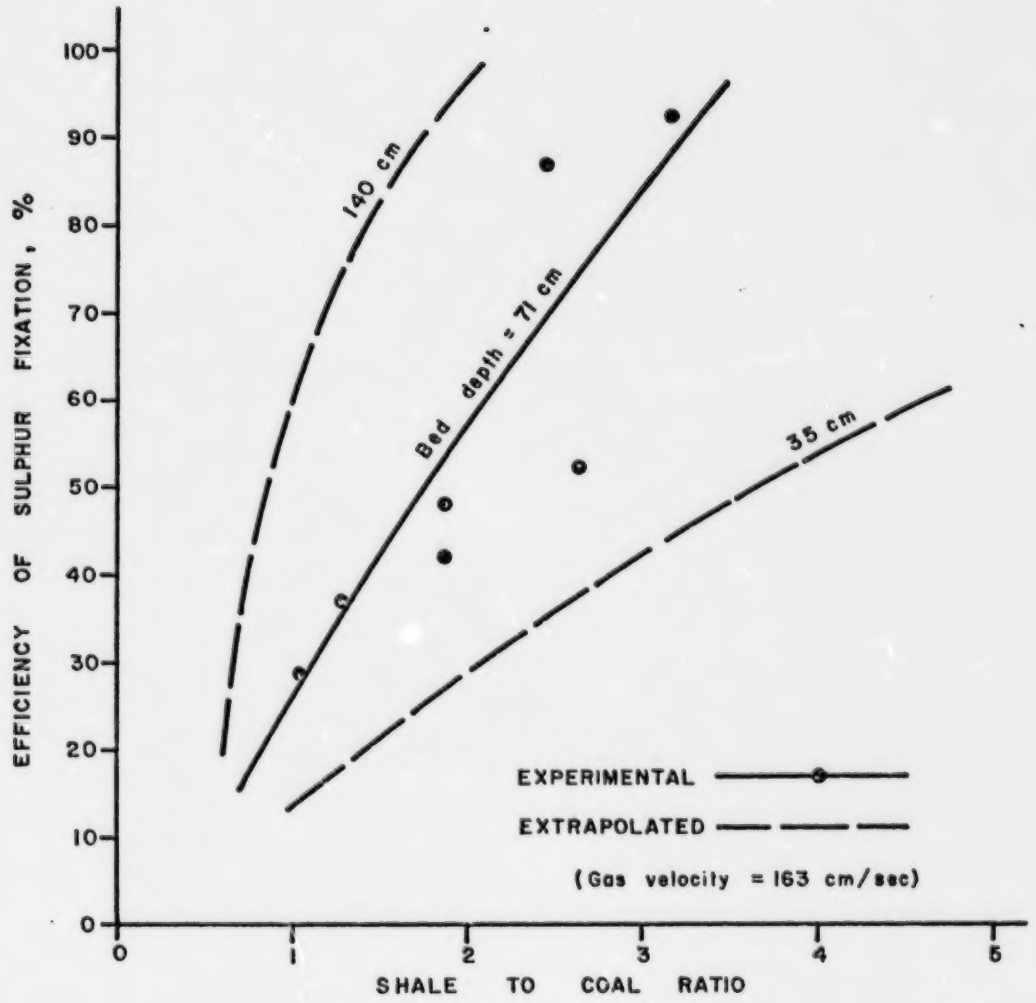

FIG. A4: Influence of the fluidized bed level on the amount of sulphur fixation, for different ratios of shale to coal.

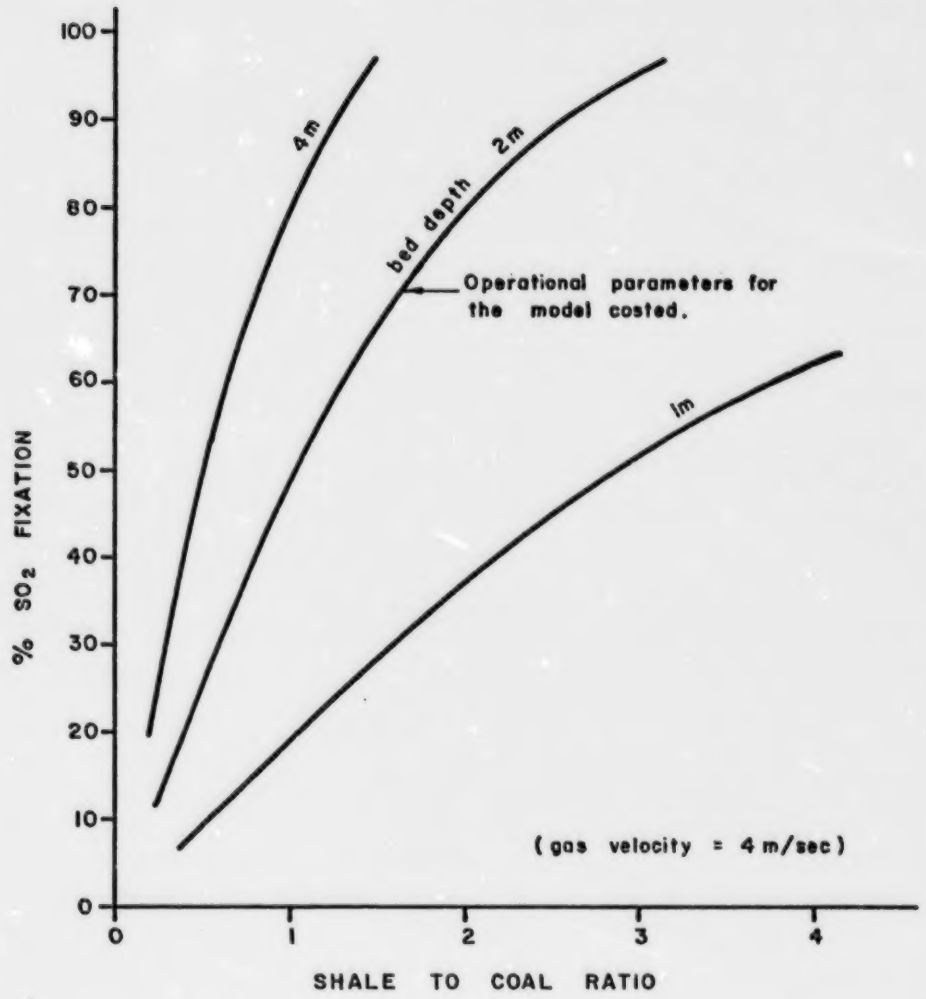

FIG. A5: Calculated values for the fixation of SO_2 in shale as a function of the shale to coal ratio for three fluidized bed levels.

APPENDIX B
PRELIMINARY DESIGN CALCULATIONS

APPENDIX B
PRELIMINARY DESIGN CALCULATIONS

MASS AND ENERGY BALANCES

In order to determine the size of the scrubber and to ensure that an operating temperature of about 850°C can be maintained, mass and energy balances have been carried out.

For a typical 200 MWe power plant, operating on high volatile high sulphur bituminous coal, the coal feed rate is about 2,000 tonne/day ($\simeq$ 23 Kg S^{-1}). From Table B1 at 10% excess air this would require 246 Kg S^{-1} of air to produce 265 Kg S^{-1} of flue gases which contain $\simeq$ 2% oxygen and 0.6% SO_2. A similar calculation has been carried out for the combustion of shale and the results are given in Table B2.

Based on Tables B1 and B2, three mass balances for the FBSC have been calculated, these were for shale/coal ratios of 2.5:1, 3:1 and 5:1 given in Tables B3 and B5, respectively. In all three cases the available oxygen in the flue gases coming out of the boiler has been taken into account.

The energy balances for the three shale/coal ratios mentioned above are given in Table B6 and B8. Each table contains an energy balance on the fluidized bed air pre-heater as well as the scrubber itself. The net thermal outputs from the scrubber are 261.6, 315.5 and 528 MW for shale/coal ratios of 2.5:1, 3:1 and 5:1 respectively. This corresponds to an electrical output of 90, 109 and 181 MWe, respectively. The summary of mass and energy balances are shown in Figures B1 to B3.

CALCULATION OF BED AREA

For a shale/coal ratio of 2.5:1, Table B3 shows that the mass flow rate of gases leaving the scrubber is 390 $Kg\ S^{-1}$. At an operating temperature of 850°C, this corresponds to a volumetric flow rate of 1242 $m^3\ S^{-1}$. For a design velocity of 4.36 $m\ S^{-1}$, the area of the bed is 285 m^2.

The design velocity was selected on the basis of actual and extrapolated experimental results given in Appendix A, see Figures A2 to A5.

Table B1: MATERIAL BALANCE ON MINTO COAL

Coal Analysis (WT%):

Moisture	Ash	Volatilies	Fixed Carbon	Sulphur
1.2	18.2	27.6	46.1	6.9

Combustion Calculations:

	Carbon	Hydrogen	Sulphur
- Weight, Kg/ 100 Kg coal	70.0	4.0	7.0
- Convert to K mol	5.83	2.0	0.22
- Oxygen required for complete combustion K mol	5.83	1.0	0.22
- Total oxygen requirement K mol		7.05	
- Total oxygen requirement Kg	7.05 X 32 = 225.6		
- Total air requirement Kg per 100 Kg coal	225.6 X $\frac{100}{23.2}$ = 972.4		
- Stoichiometric air/fuel ratio Kg/Kg	9.72:1		
- Air/fuel ratio (10% excess air)	10.7:1		

Composition of flue gases:

	% v/v (dry basis)
O_2	1.96
CO_2	16.22
SO_2	0.61
N_2	81.21

Table B2: MATERIAL BALANCE ON ALBERT COUNTY OIL SHALE (25 gal/Ton)

Shale Analysis (WT% dry):

Carbon	Hydrogen	Oxygen	Sulphur
15.54	1.98	7.93	1.13

Combustion Calculations:

	Carbon	Hydrogen	Sulphur	Oxygen
- Weight, Kg/100 Kg Shale	15.54	1.98	1.13	7.93
- Convert to K mol	1.3	0.99	0.04	0.25
- Oxygen required for complete combustion K mol	1.3	0.5	0.04	- 0.25
- Total oxygen requirement K mol		1.6		
- Total oxygen requirement kg	1.6 X 32 = 51.2			
- Total air requirement Kg per 100 Kg coal	$51.2 \times \frac{100}{23.2} = 220.7$			
- Stoichiometric air/fuel ratio Kg/Kg	2.2:1			
- Air/fuel ratio (10% excess air)	2.4:1			

Composition of flue gases:

	%v/v (dry basis)
O_2	1.9
CO_2	16.1
SO_2	-
N_2	82.0

Table B3: MASS BALANCE FOR FBSC OPERATING AT SHALE TO COAL RATIO OF 2.5:1

	Kg S^{-1}
Gas from boiler	265
Air from FBHX	115
Shale from bunker	57.5
	437.5
Gas to stack	390
Ash from bed	38.95
Dust in stack gas	3.8
Grits to cyclones	4.75
	437.5

Table B1: MASS BALANCE FOR FBSC OPERATING AT SHALE TO COAL RATIO OF 3:1

	Kg S^{-1}
Gas from boiler	265.0
Air from FBHX	142.6
Shale from bunker	69.0
	476.6
Gas to stack	419.60
Ash from bed	46.74
Dust in stack gas	4.56
Grits to cyclones	5.70
	476.6

Table B5: MASS BALANCE FOR FBSC OPERATING AT SHALE TO COAL RATIO OF 5:1

	Kg S^{-1}
Gas from boiler	265.0
Air from FBHX	253.0
Shale from bunker	115.0
	633.0
Gas to stack	538.0
Ash from bed	77.9
Dust in stack gas	7.6
Grits to cyclones	9.5
	633.0

Table B6: HEAT BALANCE FOR FBHX AND FBSC OPERATING AT SHALE TO COAL RATIO OF 2.5:1

	MW
Heat in ash	39.09
Heat removed by air	29.90
Heat in ash	9.19
	39.09

	MW
Heat in feed shale	333.5
Heat loss due to unburnt combustibles and shell heat losses*	16.675
Heat loss in gas	8.970
Sensible heat in ash	46.241
Heat to boiler	261.614
	333.5

* Heat losses was assumed to be 5%.

Table B7: HEAT BALANCE FOR FBHX AND FBSC OPERATING AT SHALE TO COAL RATIO OF 3:1

	MW
Heat in ash	46.88
Heat removed by air	35.85
Heat in ash	11.03
	46.88

	MW
Heat in feed shale	400.2
Heat loss due to unburnt combustibles and shell losses*	20.01
Heat loss in gas	9.24
Sensible heat in ash	55.49
Heat to boiler	315.46
	400.2

* Heat losses was assumed to be 5%.

Table B 8: HEAT BALANCE FOR FBHX AND FBSC OPERATING AT SHALE TO COAL RATIO OF 5:1

	MW
Heat in ash	78.13
Heat removed by air	59.75
Heat in ash	18.38
	78.13

	MW
Heat in feed shale	667.0
Heat loss due to unburnt combustibles and shell losses*	33.35
Heat loss in gas	15.06
Sensible heat in ash	92.48
Heat to boiler	528.4
	667.0

* Heat losses was assumed to be 5%.

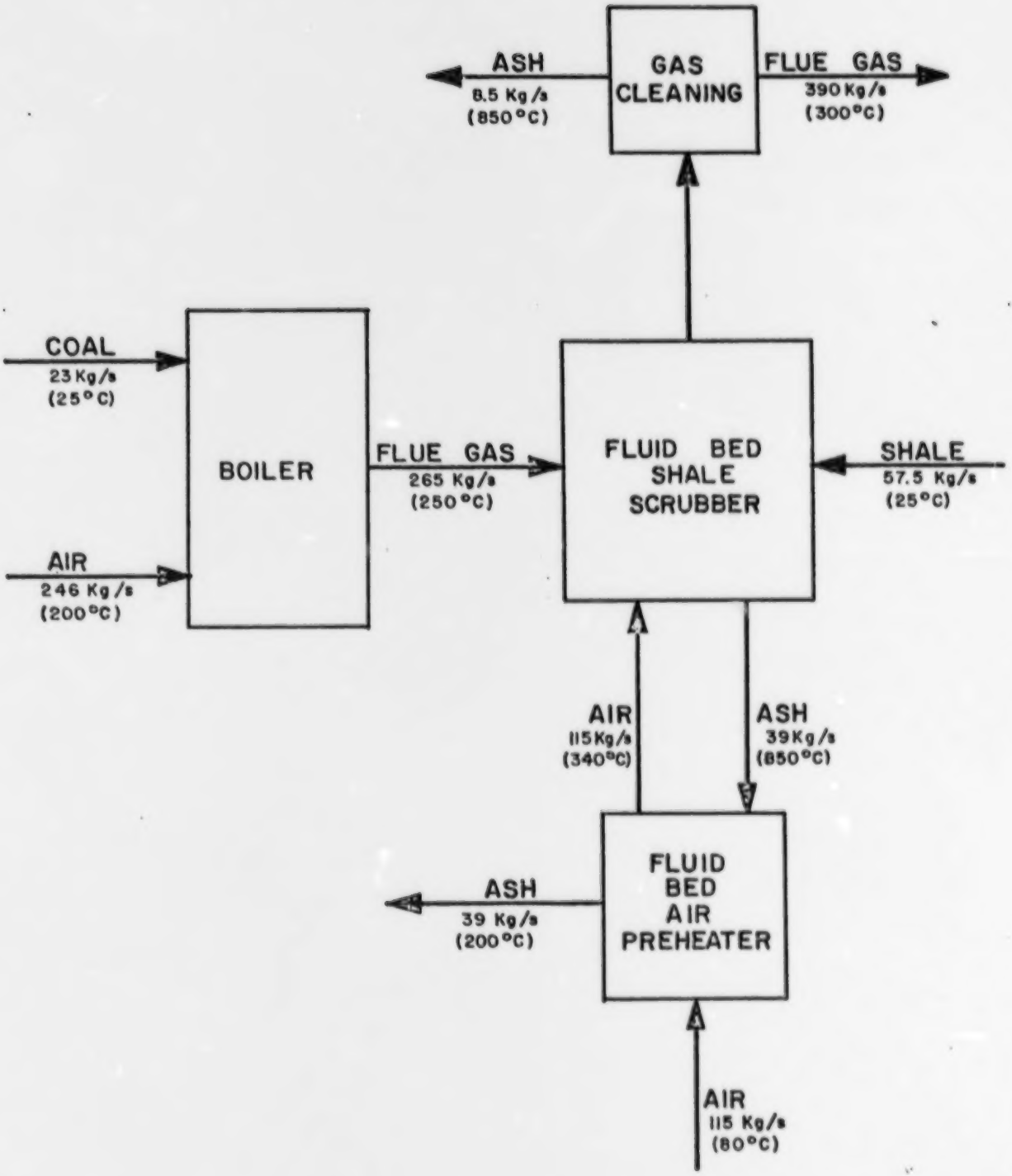

FIG. B1: Mass and energy balance for FBSC operating on shale to coal ratio of 2.5:1.

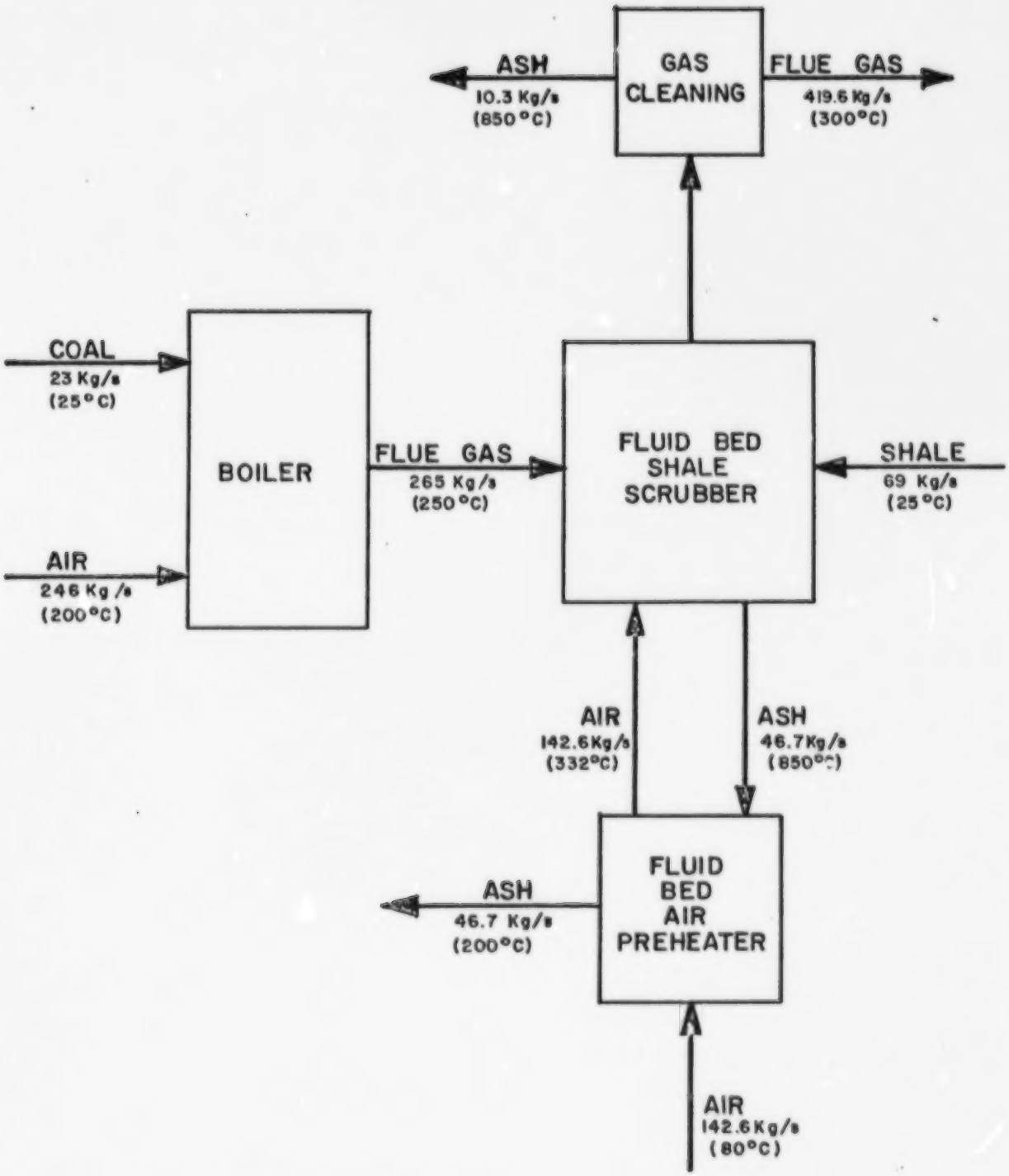

FIG. B2: Mass and energy balance for FBSC operating on shale to coal ratio of 3 : 1.

APPENDIX C
CAPITAL AND OPERATING COST ESTIMATES

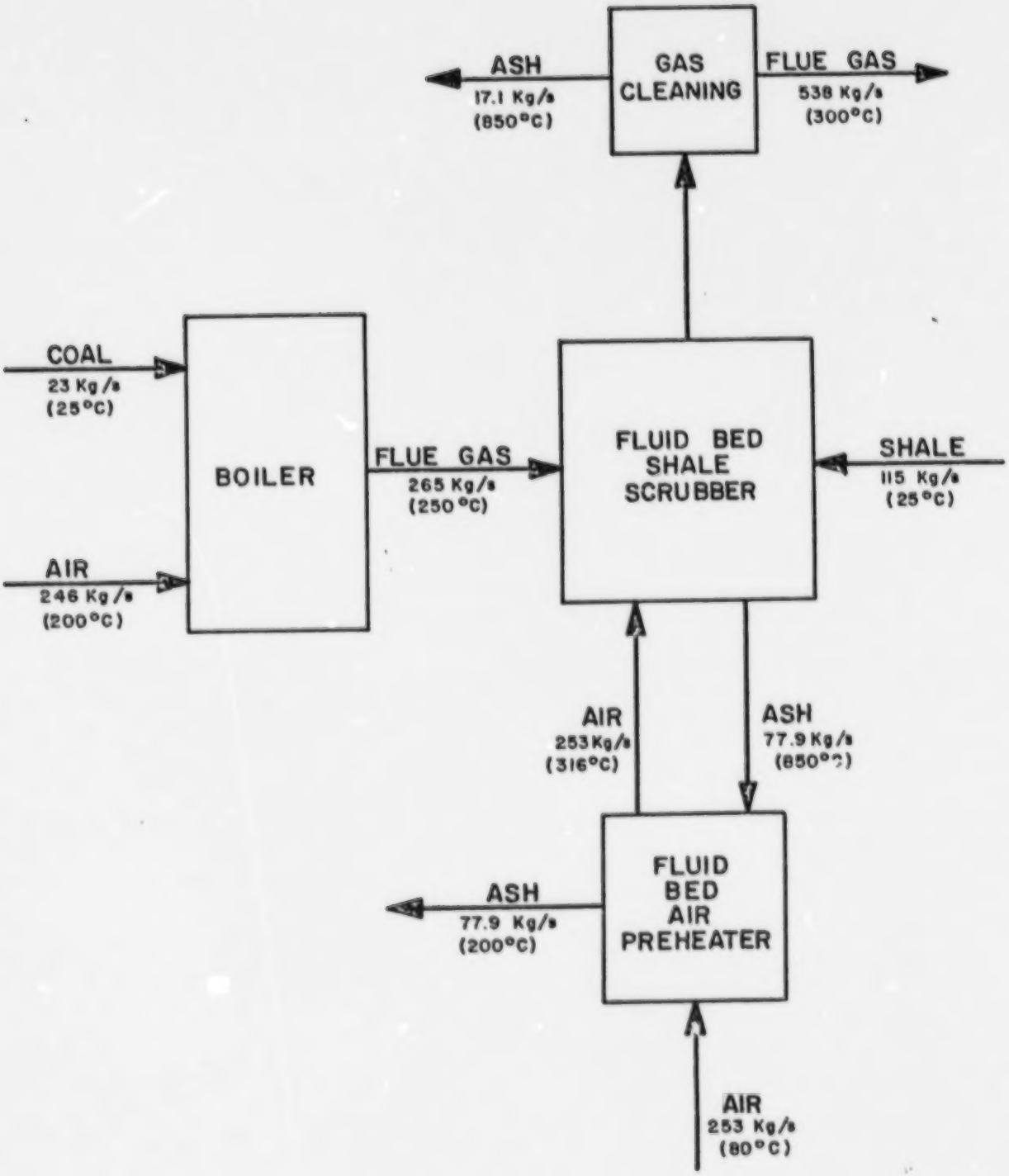

FIG. B3: Mass and energy balance for FBSC operating on shale to coal ratio of 5 : 1.

APPENDIX C

CAPITAL AND OPERATING COST ESTIMATES

CAPITAL COSTS

The capital costs estimate given in Table C1, was based on a study given in reference (1). To account for the difference in scale between the two plants the six-tenths rule has been used (Factor used was 0.67). To apply this rule to each item in Table C1, the parameters which predominate the cost of the item have been identified. These parameters were as follows:

A. Solid handling systems: The cost of this itme is predominantly determined by the number of feeding points see reference (2), rather than the amount of solids handled, therefore it is a function of the area of the combustor.

B. Fluid bed scrubber combustor: The cost is a function of the bed area, and the power output of the unit (number of boiler tubes).

C. Steam turbine generator units and accessory electrical equipment: The cost is a function of the power output of the unit.

D. Instrumentation and control system: The cost is a function of the complexity of the plant.

(2) Holcomb, R. S., "Development Progress on the Atmospheric Fluidized Bed Coal Combustor for Co-generation Gas Turbine System for Industrial Co-generation Plants". Trans. ASME, 102, 292, April 1980.

The factors calculated using the above rule were as follows:

Item	FBSC	Plant 600 MWe(1)	F	$F^{0.67}$
Combustor area, M^2	285	644	0.44	0.58
Power output MWe	90	465.7*	0.19	0.32

* The plant has a gas turbine which produce an additional 127.2 MWe.

Other factors related to the design of the two plants were also taken into consideration. Using these factors the direct capital cost given in Table C1 was calculated as follows:

		600 MWe(1)	Factors	Thousand Dollars
Solid handling systems	=	21,808 X 0.5* X 1.756+		= 19,147
Fluid bed scrubber combustor	=	63,033 X ½(0.58 + 0.32) X 1.756		= 49,805
Steam turbine generator	=	29,923 X 0.32 X 1.756		= 16,814
Accessory electrical equipment	=	22,358 X 0.32 X 0.78** X 1.756		= 9,799
Instrumentation and control systems	=	6,130 X 0.5# X 1.756		= 4,725

* the value of this factor has been set at 0.5 rather than 0.58 as calculated above, because the 600 MWe plant has two combustor one of them is pressurized.

\+ this factor allow for the exchange rate U.S. to Canadian dollars as well as the rate of inflation.

** this factor accounts for not having the extra power output generated by the gas turbine.

\# this factor was set at 0.5 because the FBSC is a much less complex plant.

TABLE C1: PRELIMINARY TOTAL/DIRECT CAPITAL COST ESTIMATE FOR FBSC OPERATING ON A SHALE TO COAL RATIO OF 2.5:1

	Thousands of Dollars (1982)
Solid handling system	19,147
Fluid bed scrubber combustor	49,805
Steam turbine generator units	16,814
Accessory electrical equipment	9,799
Instrumentation and control systems	5,382
Total direct capital cost	100,947

TABLE C2: PRELIMINARY TOTAL/DIRECT CAPITAL ESTIMATE FOR A 290 MWe FLUIDIZED BED POWER PLANT OPERATING ON A SHALE/COAL RATIO OF 2.5:1

	Thousands of Dollars (1982)
Solid handling	19,147
Fluid bed combustor	71,946
Steam turbine generator	37,832
Accessory electrical equipment	22,048
Instrumentation and control system	5,382
Total direct capital cost	156,355

TABLE C3

CAPITAL COST ESTIMATE ($,000)
OIL SHALE/COAL FLUID BED CO-COMBUSTION
(290 MWe)

LOCATION: ALBERT COUNTY

Total Direct Investment	$156,355.0
Indirect Investment	
Engineering and Owners Cost	$ 15,635.0
Contingency	$ 17,199.0
Total Fixed Investment	$189,189.0
Other Capital Charges	
Interest During Construction	$ 29,797.3
Total Depreciable Capital Investment	$218,986.3

TOTAL CAPITAL INVESTMENT = $755/kw

TABLE C4

ANNUAL OPERATING COSTS
OILSHALE/COAL FLUID BED CO-COMBUSTION
(1982 CANADIAN DOLLARS)

	Annual Quantity	Unit Cost	Total Annual Cost ($,000)
DIRECT COSTS			
Oil Shale	1,606,000 ST	$ 6/ST	$ 9,636.0
Coal	642,400 ST	$48/ST	$30,835.2
Operating Labour and Supervision	100,000 Man Hr	$17.79/Man Hr	$ 1,779.0
Utilities	(As per Huber & Costello		$ 63.1
Maintenance Labour and Materials	(2.7% of Direct Investment)		$ 4,221.6
Analyses			$ 86.4
Land Fill, Truck, Spread etc	= 1,710,000	$ 2.25/ST	$ 3,847.5
TOTAL DIRECT COSTS			$50,468.8
INDIRECT COSTS			
Plant Overhead	(50% of Operating Labour, Maintenance, Analyses)		$ 3,043.5
Administration Overhead	(10% Operating Labour)		$ 177.9
Municipal & Provincial Taxes	(2.5% (15% Fixed Inv.)		$ 709.5
Insurance	(0.15% Depreciable Capital)		$ 328.5
Working Capital and Land Costs	(0.3% Direct Inv.)		$ 469.1
TOTAL INDIRECT COSTS			$ 4,728.5
TOTAL ANNUAL OPERATING COSTS			$55,197.3
Capital Recovery	(Factor 0.124143)		$27,185.6
TOTAL ANNUAL COST			$82,382.9
$2,032,320 \times 10^3$ kwhr/yr			$40.5 mill/kwhr

TABLE C5

CAPITAL COST ESTIMATE ($,000)
RETORT SPENT OIL SHALE/COAL FLUID BED CO-COMBUSTION
(290 M.e)

LOCATION: ALBERT COUNTY

Total Direct Investment	$172,164.0
Indirect Investment	
Engineering and Owners Costs	$ 17,216.4
Contingency	$ 18,938.0
Total Fixed Investment	$208,318.4
Other Capital Charges	
Interest During Construction	$ 32,801.1
Total Depreciable Capital Investment	$ 241,128.5

TOTAL CAPITAL INVESTMENT = $831/kw.

TABLE C6

ANNUAL OPERATING COSTS
RETORT SPENT OIL SHALE/COAL FLUID BED CO-COMBUSTION
(1982 CANADIAN DOLLARS)

	Annual Quantity	Unit Cost	Total Annual Cost ($,000)
DIRECT COSTS			
Oil Shale	2,096,834	N.C.	-
Coal	838,734	$48/ST	40,259.2
Operating Labour and Supervision	100,000	$17.89/Man Hr	1,779.0
Utilities			63.1
Maintenance Labour and Materials	(2.7% of Direct Investment)		4,648.4
Analyses			86.4
Land, Fill Truck, Spread, etc	2,231,031	2.25	5,091.8
TOTAL DIRECT COSTS			52,855.9
INDIRECT COSTS			
Plant Overhead	(50% of Operating Labour, Maintenance, Analyses)		3,256.9
Administration Overhead	(10% of Operating Labour)		177.9
Municipal & Provincial Taxes	(2.5%(15% Fixed Inv.)		781.2
Insurance	(0.15% Depreciable Capital)		361.7
Working Capital and Land Costs	(0.3% Direct Inv.)		516.5
TOTAL INDIRECT COSTS			5,094.2
TOTAL ANNUAL OPERATING COSTS			56,950.1
Capital Recovery			29,934.4
TOTAL ANNUAL COST			86,884.5
$2,032,320 \times 10^3$ kwhr/yr			42.8 mills/kwhr

TABLE C7

CAPITAL COST ESTIMATE ($,000)
OIL SHALE COMBUSTION SCRUBBER OPTION

LOCATION: DALHOUSIE

Total Direct Investment (Combustion Scrubber)	$ 74,334.0
Indirect Investment	
Engineering and Owners Cost	$ 7,433.4
Contingency	$ 8,176.7
Total Fixed Investment	$ 89,944.1
Other Capital Charges	
Interest During Construction (@ 12%)	$ 14,166.2
Total Depreciable Capital Investment	$104,110.3
Investment Dalhousie No.2 Plant	$176,600.0
Total Plant Including Scrubber	$280,710.3

CAPITAL INVESTMENT = $968/kw.

TABLE C8

ANNUAL OPERATING COSTS
OIL SHALE COMBUSTION SCRUBBER OPTION
(1982 CANADIAN DOLLARS)

	Annual Quantity	Unit Cost	Total Annual Cost ($,000)
PLANT SITE DALHOUSIE NEW BRUNSWICK			
DIRECT COSTS			
Oil Shale	1,606,000 ST	$15/ST	$24,090.0
Operating Labour and Supervision	60,000 Man Hr	$17.79/Man Hr	$ 1,067.4
Utilities	Estimate		$ 70.0
Maintenance Labour and Materials	(2.7% of Direct Investment		$ 2,428.5
Analyses	(As per Limestone Scrubber Option)		$ 86.4
Land Fill Truck, Spread etc	≈ 1,606,000 ST	$ 2.25/ST	$ 3,613.5
TOTAL DIRECT COSTS			$31,355.8
INDIRECT COSTS			
Plant Overhead	(50% of Operating Labour, Maintenance, Analyses		$ 1,791.2
Adminstration Overhead	(10% Operating Labour)		$ 106.7
Municipal & Provincial Taxes	(2.5% (15% Fixed Inv)		$ 337.3
Insurance	(0.15% Depreciable Capital)		$ 156.2
Working Capital and Land Costs	(0.3% Direct Investment)		$ 223.0
TOTAL INDIRECT COSTS	(Combustion Scrubber)		$ 2,614.4
TOTAL ANNUAL OPERATING COSTS	(Combustion Scrubber)		$33,970.2
Capital Recovery	(12% interest 30 yr; Factor = 0.124143)		$12,924.6
TOTAL ANNUAL COSTS	(Combustion Scrubber)		$46,894.8

TOTAL ANNUAL COSTS	(Dalhousie No.2 Plant)		
	Coal	$32,762.4	
	Capital & Operating	$26,896.2	
	Total		59,658.6
TOTAL ANNUAL COSTS	(Main Coal Plant & Combustion Scrubber)		106,553.4
$2{,}032{,}320 \times 10^3$ kwhr/yr			52.4 mills/kwhr

TABLE C9

CAPITAL COST ESTIMATE ($,000)
COAL/LIMESTONE FLUID BED CO-COMBUSTION
(290 MWe)

LOCATION: MINTO	
Total Direct Investment	$156,355.0
Indirect Investment	
Engineering and Owners Costs	$ 15,635.0
Contingency	$ 17,199.0
Total Fixed Investment	$189,189.0
Other Capital Charges	
Interest During Construction	$ 29,797.3
Total Depreciable Capital Investment	$218,986.3

TOTAL CAPITAL INVESTMENT = $755/kw.

TABLE C10

ANNUAL OPERATING COSTS
COAL/LIMESTONE FLUID BED COMBUSTION
(290 MWe)

	Annual Quantity	Unit Cost	Total Annual Cost ($,000)
DIRECT COSTS			
Coal	931.480 ST	$39/ST	$ 36,327.7
Limestone	1,210,924 ST	$20/ST	$ 24,218.5
Operating Labour and Supervision	100,000Man/hr	$17.79/Man Hr	$ 1,779.0
Utilities			$ 63.1
Maintenance Labour and Materials	(2.7%of Direct Investment)		$ 4,221.6
Analyses			$ 86.4
Land, Fill,Truck, Spread, etc	2,232,000 ST	$ 2.25/ST	$ 5,022.0
TOTAL DIRECT COSTS			$ 71,718.3
INDIRECT COSTS			
Plant Overhead	(50% of Operating Labour, Maintenance, Analysis)		$ 3,043.5
Administration Overhead	(10% Operating Labour)		$ 177.9
Municipal & Provincial Taxes	(2.5%(15% Fixed Inv.)		$ 709.5
Insurance	(0.15% Depreciable Capital)		$ 328.5
Working Capital and Land Costs	(0.3% Direct Inv.)		$ 469.1
TOTAL INDIRECT COSTS			$ 4,728.5
TOTAL ANNUAL OPERATING COSTS			$ 76,446.8
Capital Recovery	(Factor 0.124143)		$ 27,185.6
TOTAL ANNUAL COST			$103,637.4
$2,032,320 \times 10^3$ kwhr/yr.			51.0 mills/kwhr.

TABLE C11

CAPITAL COST ESTIMATE ($,000)

LIMESTONE SCRUBBER OPTION

LOCATION: DALHOUSIE	Dalhousie (200 MWe) Projection (Retrofit) (1982)
Total Direct Investment	$ 30,768.3
Indirect Investment	
Engineering Design and Supervision (8% Direct Inv.)	$ 2,461.5
Construction Expenses (16% Direct Inv.)	$ 4,922.9
Contractor Fees (6% Direct Inv.)	$ 1,846.1
Contingency (20% Direct Inv.)	$ 6,153.7
Total Indirect Investment	$ 15,384.2
Total Fixed Investment	$ 46,152.6
Other Capital Charges	
Interest During Construction (@ 12% Int.)	$ 7,269.0
Total Depreciable Capital Investment	$ 53,421.6
Investment Dalhousie No. 2 (1982 Dollars)	$176,600.0
Total Plant Investment Including Scrubber	$230,021.6

CAPITAL INVESTMENT = $1150/kw

TABLE C12

ANNUAL OPERATING COSTS
LIMESTONE SCRUBBER OPTION
(1982 CANADIAN DOLLARS)

	Annual Quantity	Unit Cost	Total Annual Cost ($,000)
DIRECT COSTS			
Limestone	142,877 ST	$16/ST	$ 2,286.0
Operating Labour and Supervision	45,000 Man Hr	$17.79/Man Hr	$ 800.6
Utilities Steam, Process Water Electricity	(Based on CEA Report (78-98) with escalation for limestone tonnage and cost escalation = 1.04 X 1.279		$ 2,884.2
Maintenance, Labour and Materials	(9% of Direct Investment)		$ 2,769.1
Analyses	4000 Hrs.	$21.60 Hr.	$ 86.4
Land Fill, Truck Spread, etc	245,748 ST	3.11/ST	$ 765.3
TOTAL DIRECT COSTS			$ 9,590.6
INDIRECT COSTS			
Plant Overhead	(50% of Operating Labour, Maintenance, Analyses)		$ 1,828.1
Administration Overhead	(10% of Operating Labour)		$ 80.1
Municipal & Provincial Tax	(2.5% (15% Fixed Inv.)		$ 173.1
Insurance	(0.15% Depreciable Capital)		$ 80.1
Working Capital and Land Costs	(0.3% Direct Investment)		$ 92.3
TOTAL INDIRECT COSTS	(Scrubber)		$ 2,253.7
TOTAL ANNUAL OPERATING COST	(Scrubber)		$11,844.3
Capital Recovery	(12% Interest 30 yr; Factor = 0.124143)		$ 6,631.9
TOTAL ANNUAL COSTS	(Scrubber		$18,476.2
$1,401,600 \times 10^3$ kwhr/yr			13.2 mill/kwhr.

TOTAL ANNUAL COSTS	(Dalhousie No. 2 @ 80% Capacity)		
	Coal	$34,304.2	
	Capital & Oper. Cost	$26,896.2	$61,200.4
$1{,}401{,}600 \times 10^3$ kwhr/yr			43.7 mill/kwhr
TOTAL ANNUAL COSTS	(Dalhousie No.2 with Limestone Scrubber		56.9 mill/kwhr

* Estimate Supplied by Carl Flin N.B. Power
(Based on 15% over 30 yr of $883/kw Capital.

NOTES

Dalhousie No. 2 Rating

Existing 2200 TPD Coal @ 23.14 million BTU/T.
Coal Washed Product = 26 million BTU/T @ 6% S (P. Whalen N.B. Power)
= 1958 TPD Coal
Limestone based on 1.41 moles $CaCO_3$ per mole SO_2

$$1 \text{ Ton Coal} = \frac{100.08 \times 1.41}{64.06 \times 0.90} \times 0.06 \times \frac{64.06}{32}$$

= 0.294 toms limestone

Design Capacity = 1958 X 0.294 X 365 = 210,113 STY limestone
@ 85% Sulphur Capture 178,596 STPY

Scale from CEA Estimate (Research Program 78-98)

$28,742,700 (1979 Dollars) for 500 MWe Plant
Burning 3.5% S Coal

For Dalhousie Plant

From CEA Report Scale $7,718.00 on limestone $\left(\frac{178,596}{171,300}\right)^{0.6}$

Materials Handling and Waste Treatment = $7,914,510

Scrubbing Scale 21,023,800 on Gas Flow

$\left(\frac{2}{5}\right)^{.6}$ X $21,023,800 = $12,132,414

Total Cost (1979) for Dalhousie No. 2 Scrubber

$$= \$20,046,800 \times \frac{305.3}{238.7} = \$25,640,243 \text{ (1982 Dollars)}$$

From CEA Recomendation 20% extra Cost for Retrofit = $30,768,291

Cost of Coal (51 + 9/T Coal Cleaning)

= $60/T Clean Coal @ Dalhousie
= 1958 X 0.80 X 365 X $60
= $34,304,160

APPENDIX D
OIL SHALE MINING COSTS

March 19, 1982.

Subject: Capital and Mining costs for a 6000 Ton/Day Open Pit Oil Shale Mine.

Assumptions:

1. Mine will produce 6000 tons per day or 42,000 tons over a 5 day work week.
2. Mine site consists of fairly rugged topography with relatively heavy tree growth.
3. Oil Shale occurs over large area and therefore waste rock will be minimal.
4. No primary crushing is considered.

Capital Costs: (1982)

1. Site preparation, plant and pit roads
   Cost = $5000\ T_p^{0.5}$
   = $700,000

2. Stripping costs
   A 32 feet layer of overburden is assumed over a 1500'x1500' area.
   (a) If the preproduction stripping is of a soil nature:
   Cost = $\$800\ T_o^{0.5}$
   = $2,500,000
   (b) If the preproduction stripping is of a rock nature:
   Cost = $\$8500\ T_o^{0.5}$
   = 27,000,000
   An average between (a) and (b) will be allocated for preproduction stripping costs.
   ∴ stripping costs = $15,000,000

3. Open Pit Equipment
   (a) Size and number of pit shovels
   Size = $0.13\ T_p^{0.4}$
   = 5 yards

   (b) No. of units required
   No. = $\frac{0.007\ T_p^{0.8}}{S}$

(c) Size and number of trucks

Truck size (t) = $85^{1.1}$

= 50 tons

(d) Number of trucks required

$$\text{No.} = \frac{0.2\ T_p^{0.8}}{t}$$

= 6

Cost of fleet truck = $6 \times 9000 \times 50^{0.85}$

= $2,200,000

Cost of shovel fleet = $2 \times 230,000 \times 5^{0.73}$

= $2,200,000

Total cost of pit equipment

$$= 6000\ T_p^{0.7} + 5000\ T_p^{0.5}$$

= $5,800,000

Miscellaneous Equipment

Cost = Total cost - Shovel and truck costs

= $1,400,000

4. Open Pit Maintenance Facilities

Cost = $150,000\ T_p^{0.3}$

= $3,400,000

Total Capital Costs:

1.	Site Preparation	....	700,000
2.	Stripping	....	15,000,000
3.	Open Pit Equipment	....	5,800,000
4.	Open Pit Maintenance Facilities	....	3,400,000
		Total	24,900,000

Mining Costs (1982)

Number of Open Pit Employees

1.	Drilling and Blasting:	$0.075(T_p)^{0.5}$	= 8)
2.	Loading :	$0.110(T_p)^{0.5}$	=11)
3.	Truck Haulage and Roads :	$0.035(T_p)^{0.7}$	=21)Nm
4.	Miscellaneous :	$0.070(T_p)^{0.5}$	= 7)
5.	Maintenance :	$0.210(T_p)^{0.5}$	=20)
6.	Mine Staff :	$0.108(T_p)^{0.5}$	=11)
7.	Electrical Service :	0.03 Nm	= 3
8.	Plant Service :	0.04 Nm	= 4
9.	General Administration:	0.07xNm	= 6

Total Number of employees =91

1. Operating Labour Cost:

$$= \frac{58.563}{T_p^{0.5}} + \frac{3.591}{T_p^{0.3}}$$

= 1.24/Ton

2. Operating Supplies Cost:

$$= \frac{13.40}{T_p^{0.5}} + \frac{1.24}{T_p^{0.3}} + \frac{0.90}{T_p^{0.2}}$$

= 0.54/Ton

3. Administration and General Services

Wages	(a)	Electrical Services	: 480.00
	(b)	Plant Services	: 332.00
	(c)	General Administration	: 750.00
	(d)	Fringe Benefits	: 547.00
		Total	$2109.00

Supplies: General Plant Services

$= 6T^{0.5}$
= $680.00

General Administration Expense

= $533.00

Total Administration and General Services

Cost = $3322.00
Cost = $0.55/Ton

Total Mining Costs

1.	Operating Labour	1.24
2.	Operating Supplies	0.54
3.	Administration and General Services	0.55
	Total Cost/Ton.....	2.33